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Chen et al.

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(54) **MONITORING DRILLING CONDITIONS AND ESTIMATING ROCK PROPERTIES**

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E21B 21/08 (2006.01)
E21B 47/04 (2012.01)
E21B 47/013 (2012.01)

(52) **U.S. Cl.**
CPC ***E21B 49/003*** (2013.01); ***E21B 21/08*** (2013.01); ***E21B 47/04*** (2013.01); *E21B 47/013* (2020.05)

(58) **Field of Classification Search**
CPC E21B 49/00; E21B 49/003; E21B 47/013
See application file for complete search history.

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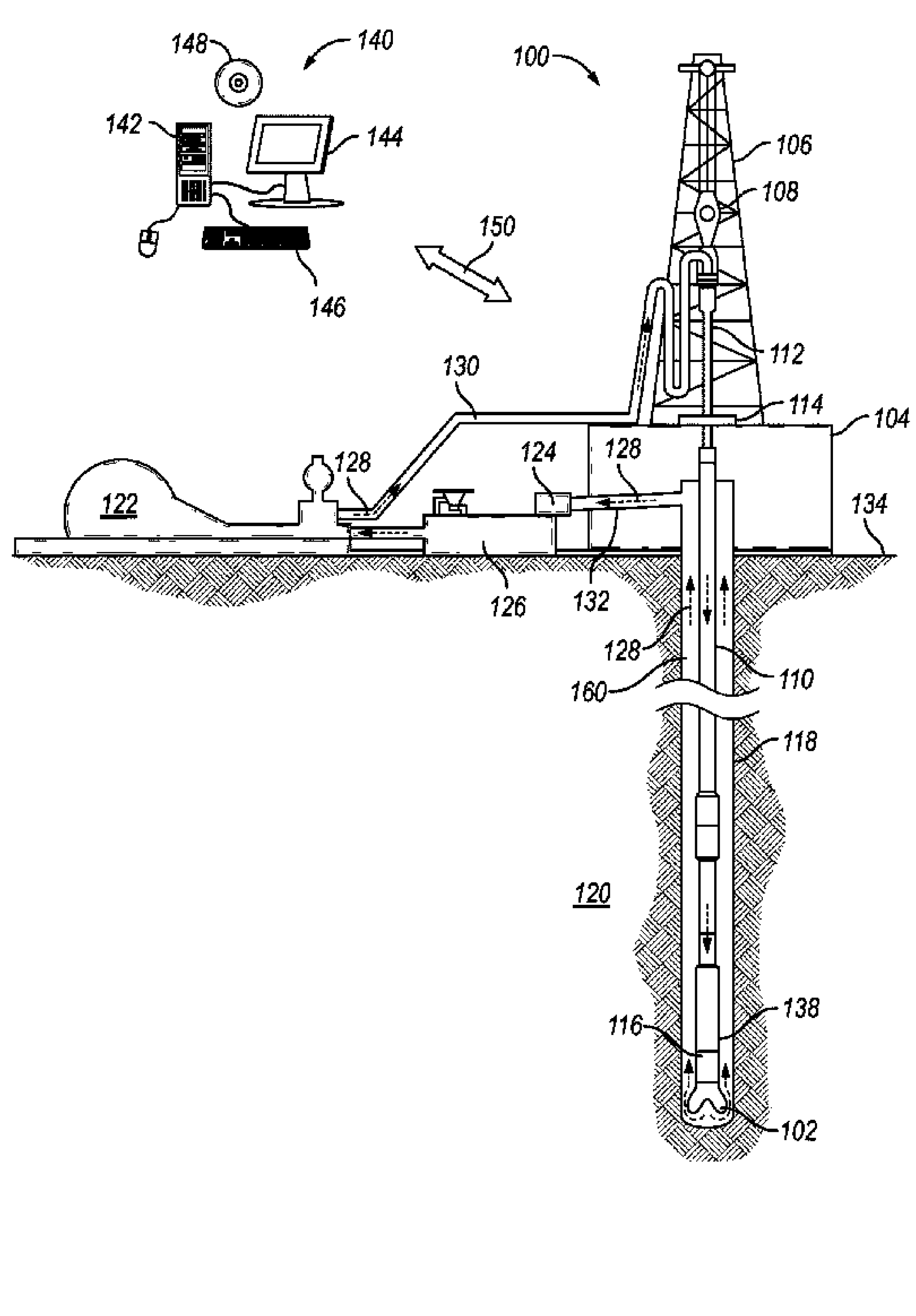
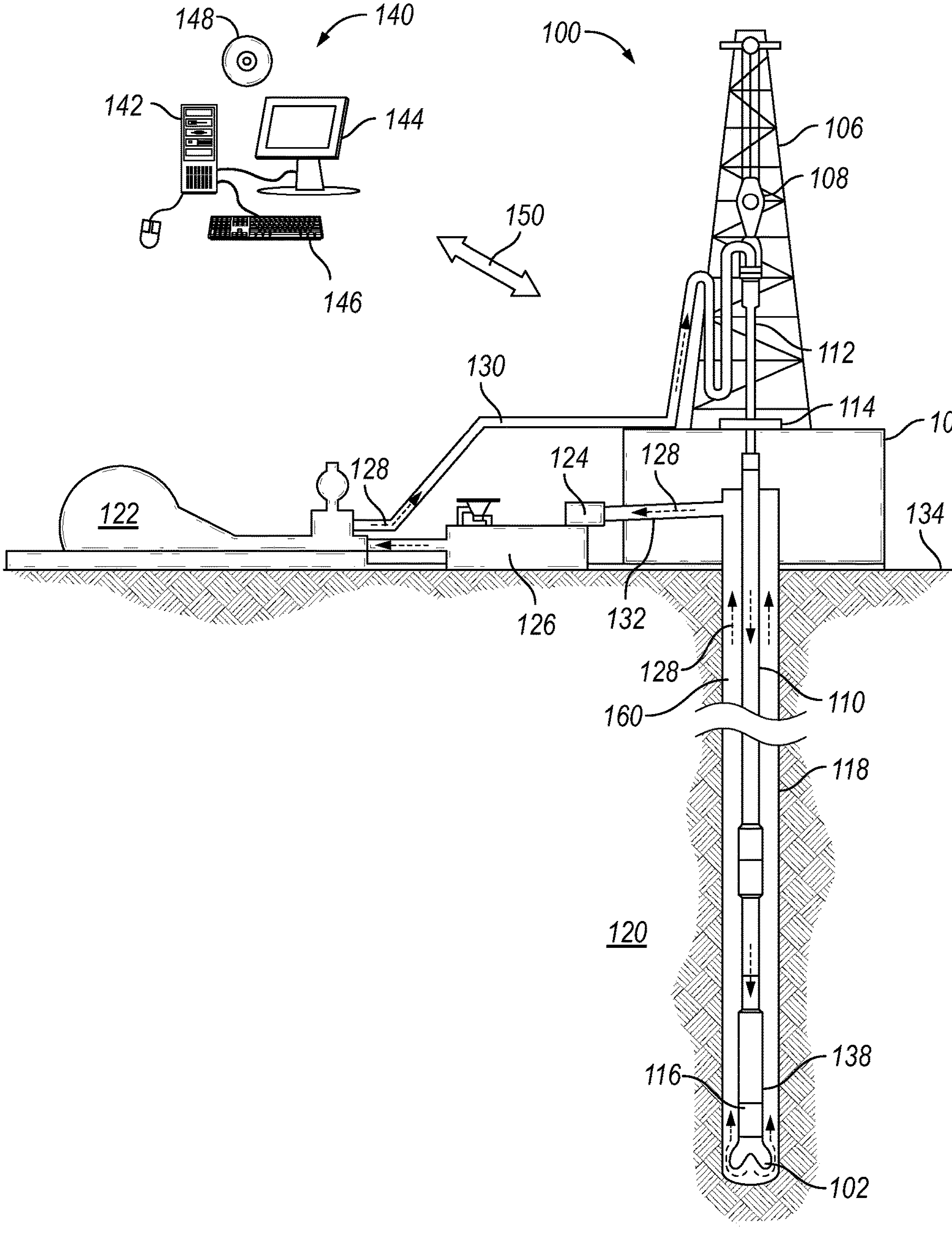
(57) **ABSTRACT**

A method and a system for a confined compressive strength (CCS) and an unconfined compressive strength (UCS) for one or more bedding layers. The method may include identifying a depth interval during a drilling operation as a distance between a first depth and a second depth, measuring one or more drill bit responses within the depth interval using a sensor package disposed on the drill bit, identifying one or more torsional bit vibrations, and identifying one or more bedding layers of the formation within the depth interval from the one or more torsional bit vibrations. The method may further include identifying the (CCS) and the (UCS) for each of the one or more bedding layers and identifying a bit wear of the drill bit within each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

22 Claims, 13 Drawing Sheets




148
140
100
142
144
106
108
150
146
112
130
114
104
128
124
128
122
134
126
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160
110
118
120
138
116
102

FIG. 1

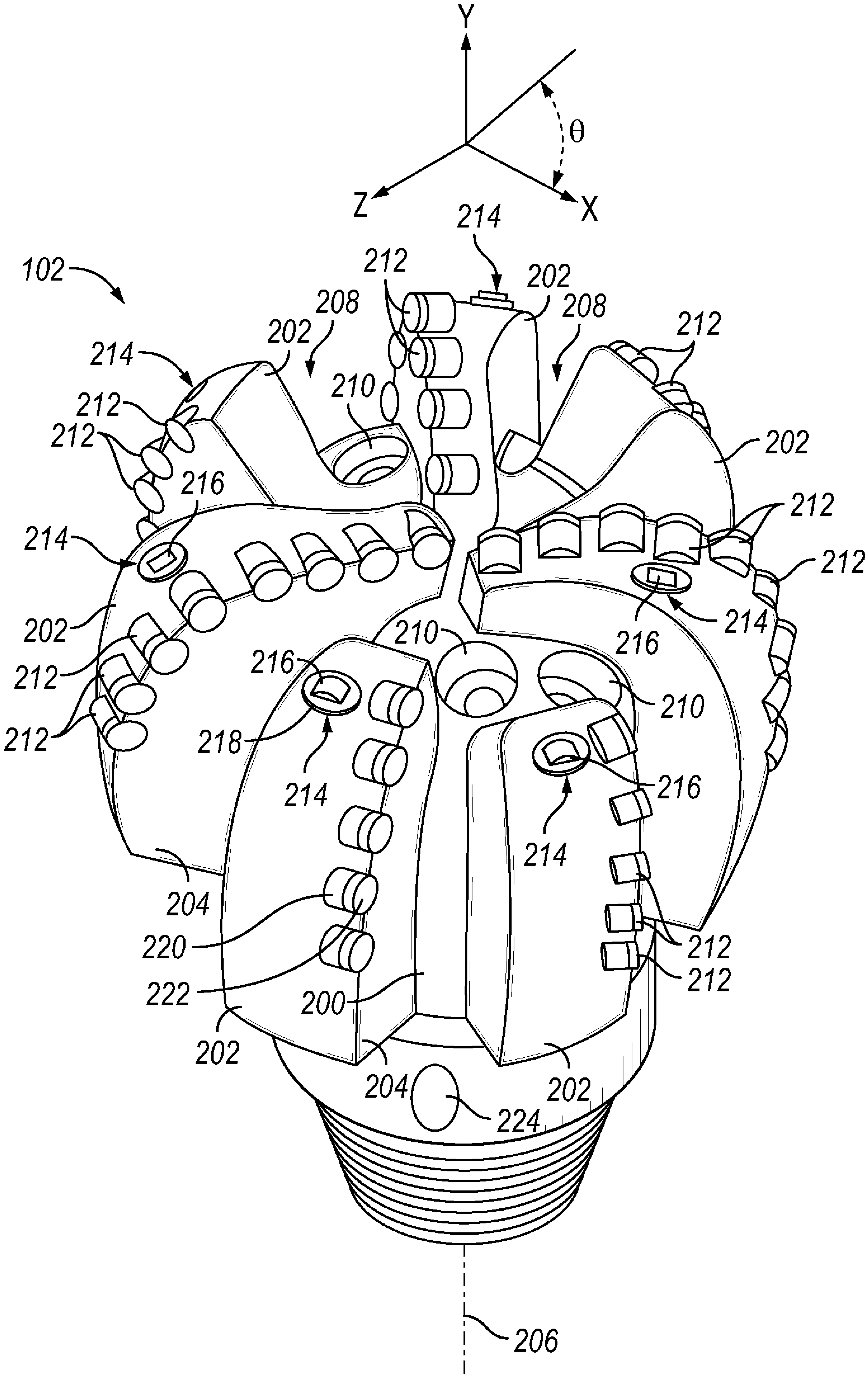


FIG. 2

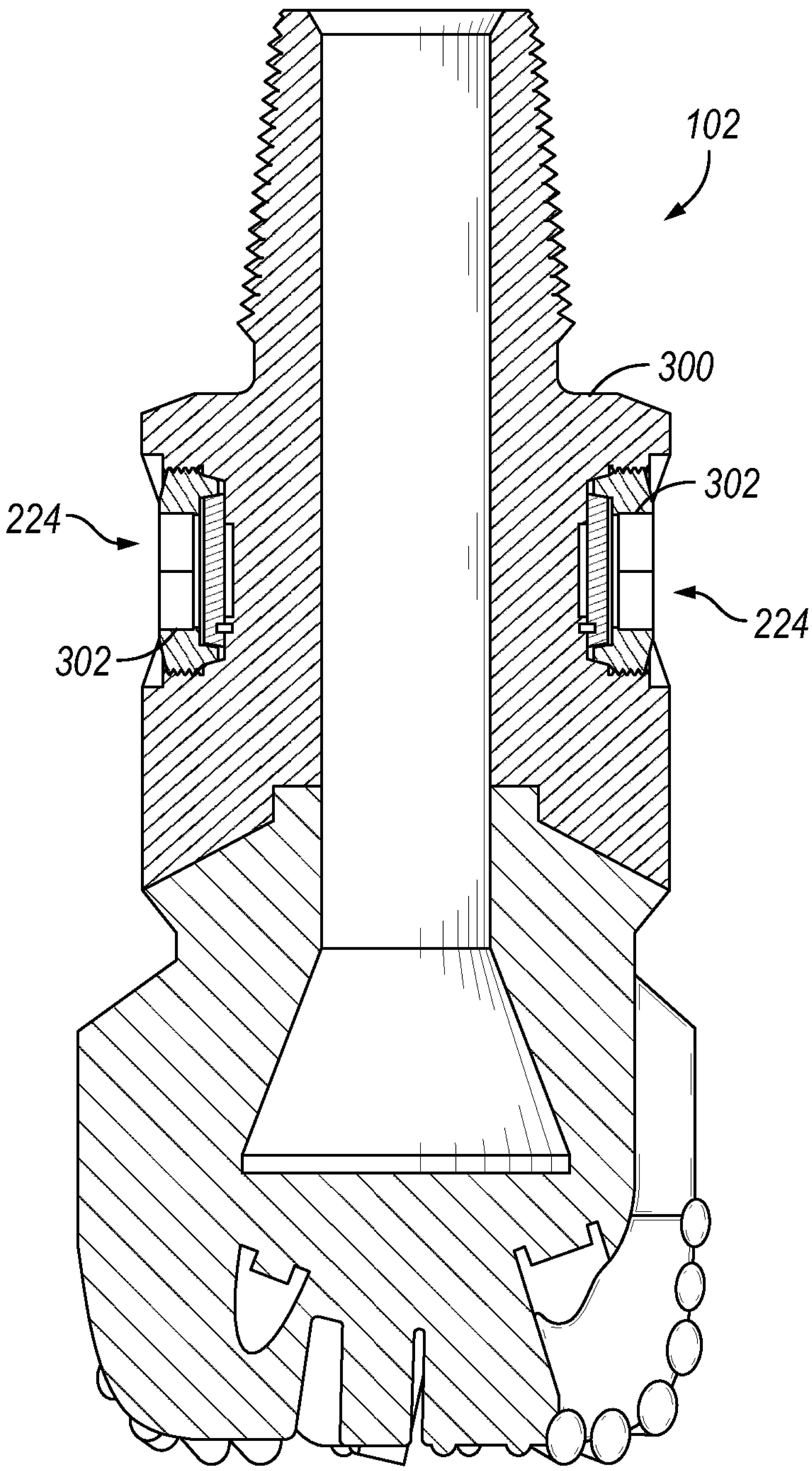


FIG. 3

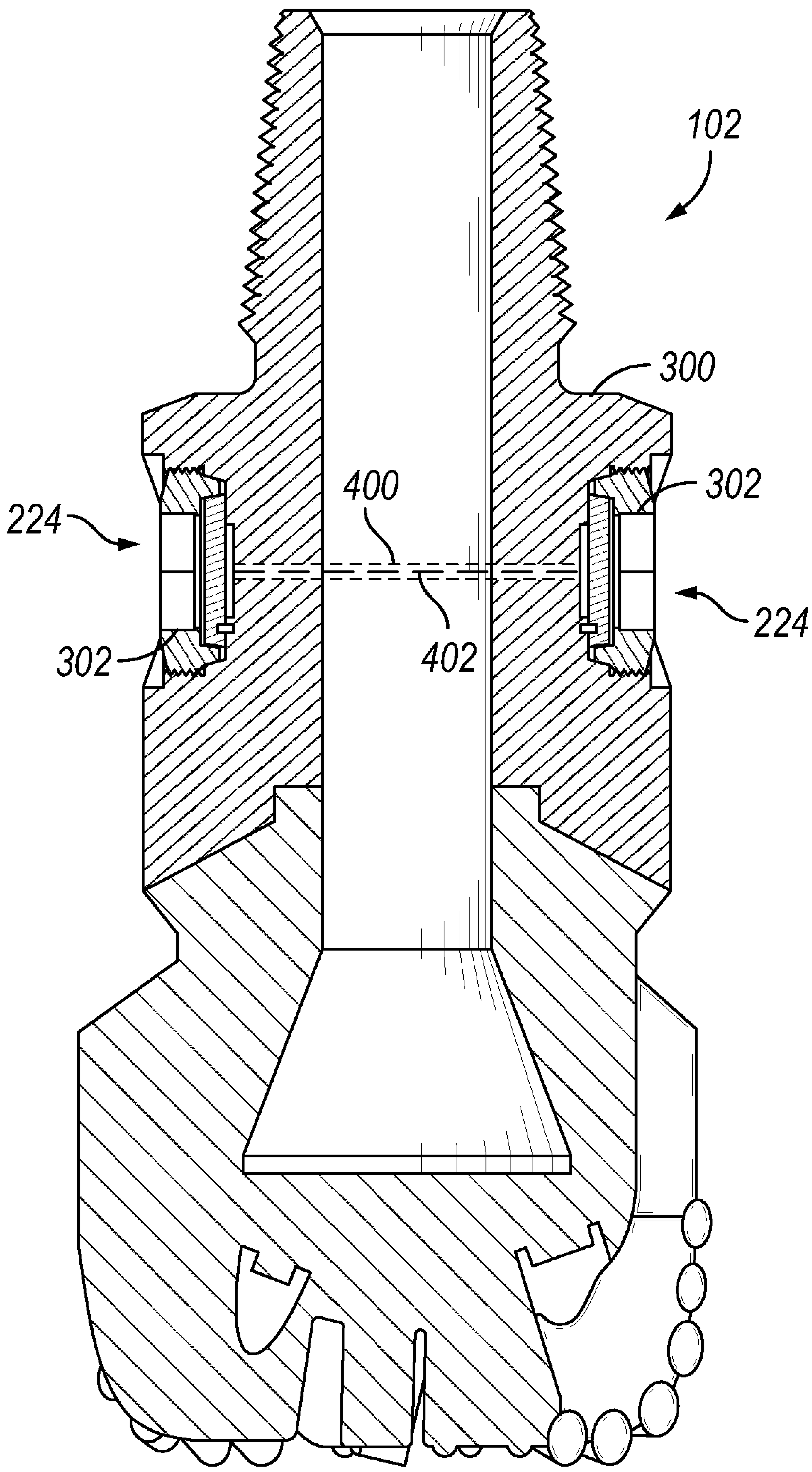


FIG. 4

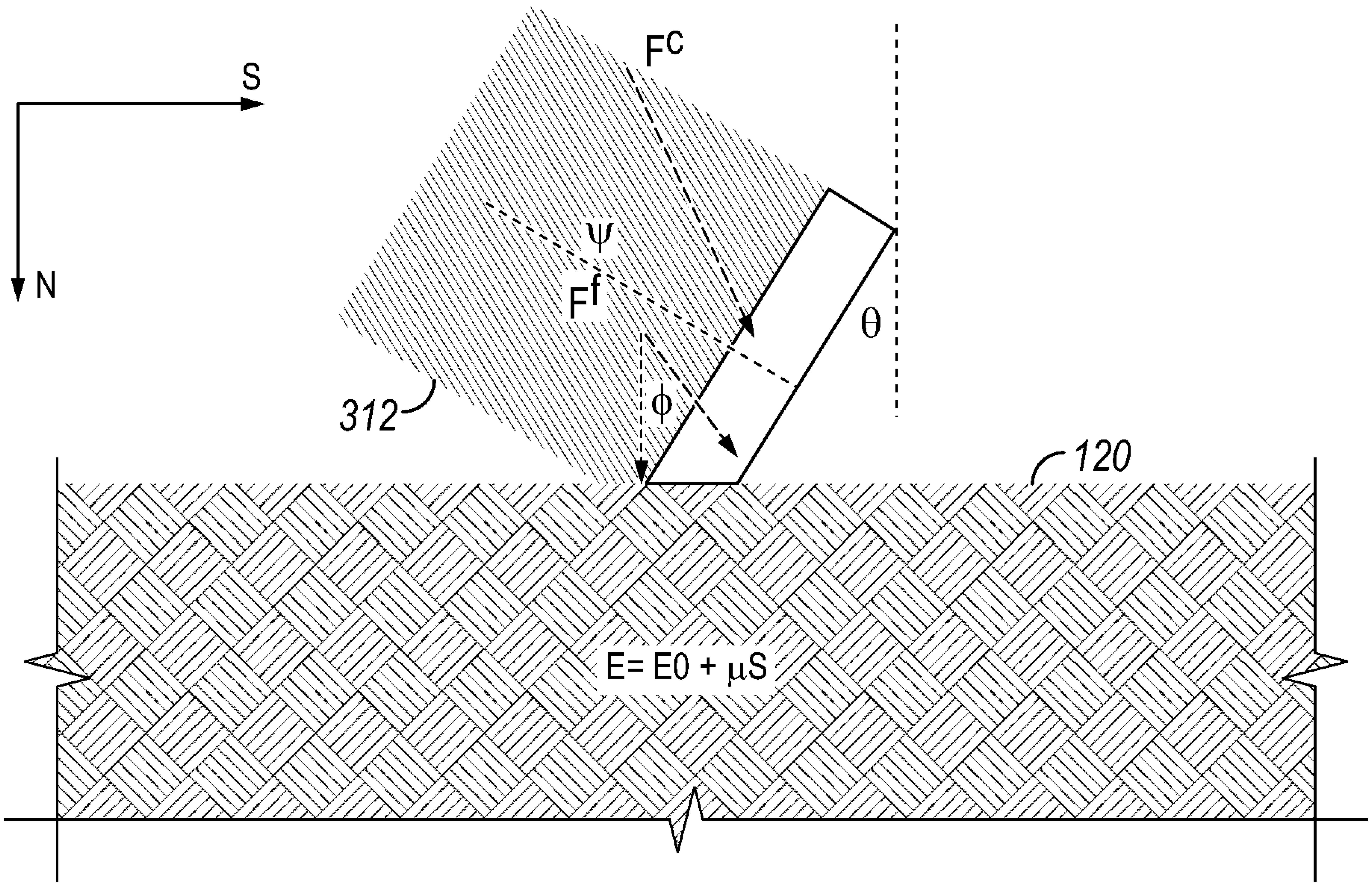

S
N
F^c
ψ
F^f
θ
ϕ
312
120
E= E0 + μS

FIG. 5

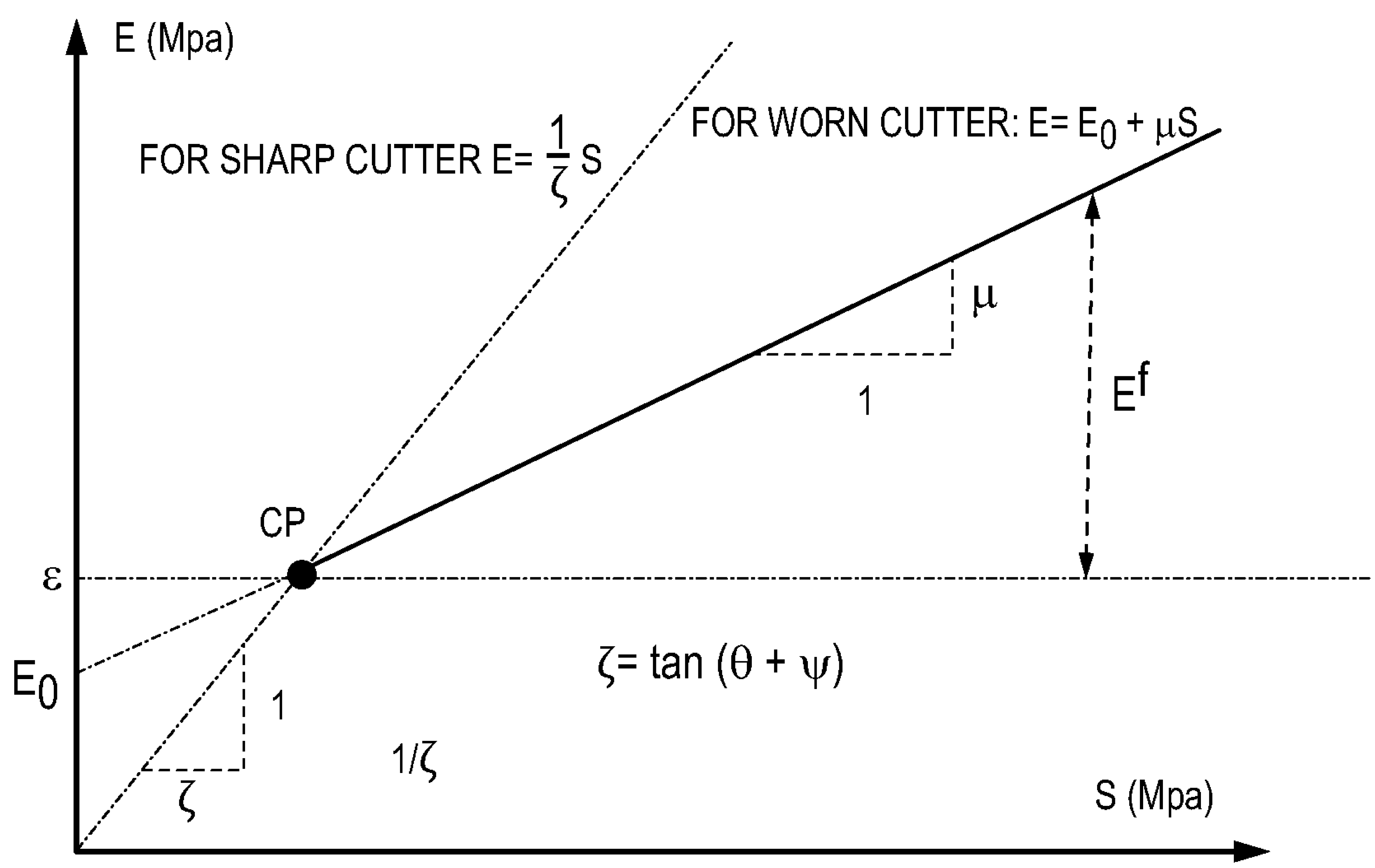
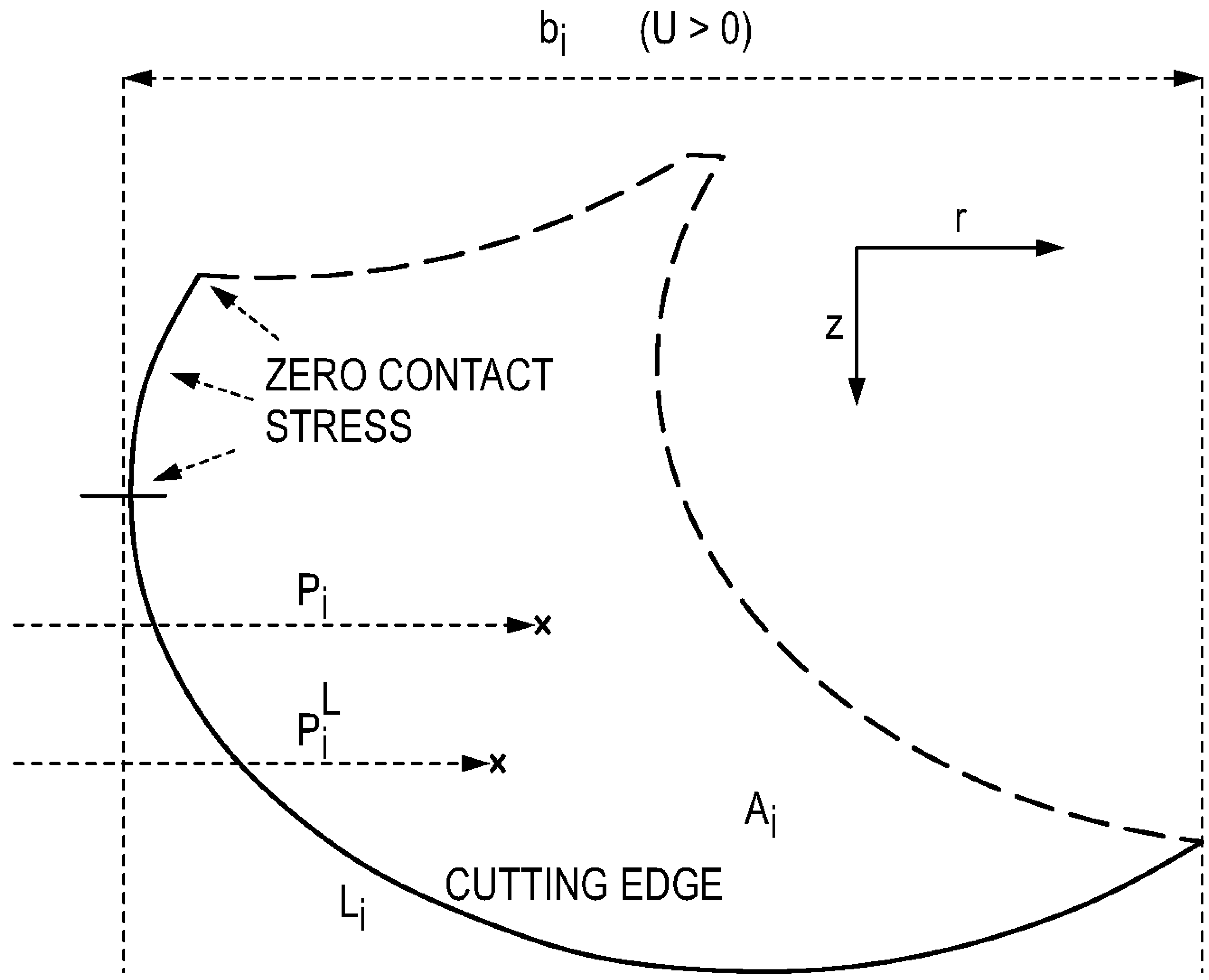
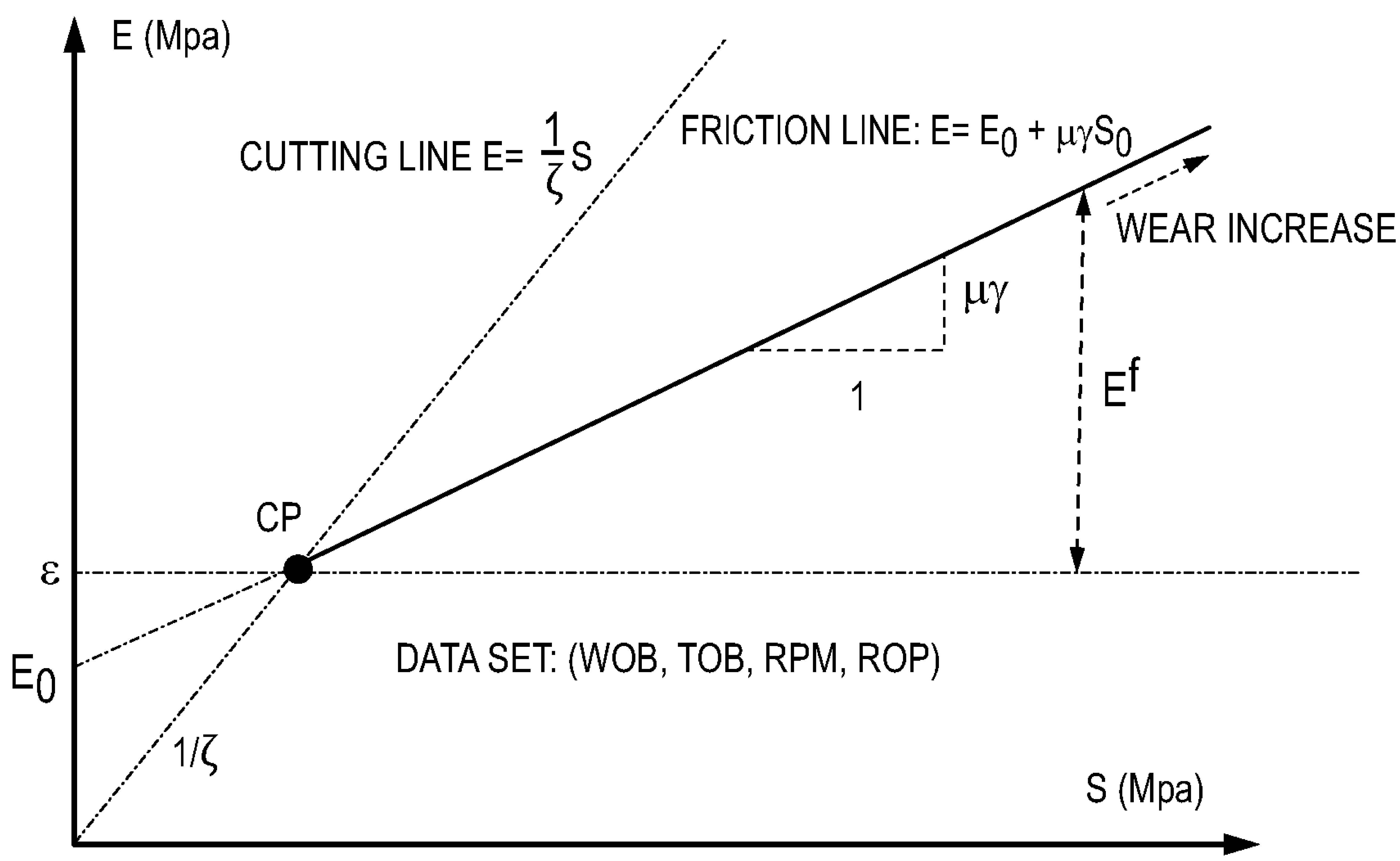

E (Mpa)
FOR SHARP CUTTER E= 1/ζ S
FOR WORN CUTTER: E= E0 + μS
μ
1
E^f
CP
ε
E0
ζ= tan (θ + ψ)
1
1/ζ
ζ
S (Mpa)

FIG. 6



b_i (U > 0)
r
z
ZERO CONTACT STRESS
P_i
P_i^L
A_i
CUTTING EDGE
L_i

FIG. 7



E (Mpa)
CUTTING LINE $E=\frac{1}{\zeta}S$
FRICTION LINE: $E=E_0+\mu\gamma S_0$
WEAR INCREASE
$\mu\gamma$
1
E^f
CP
ε
E_0
DATA SET: (WOB, TOB, RPM, ROP)
$1/\zeta$
S (Mpa)

FIG. 8

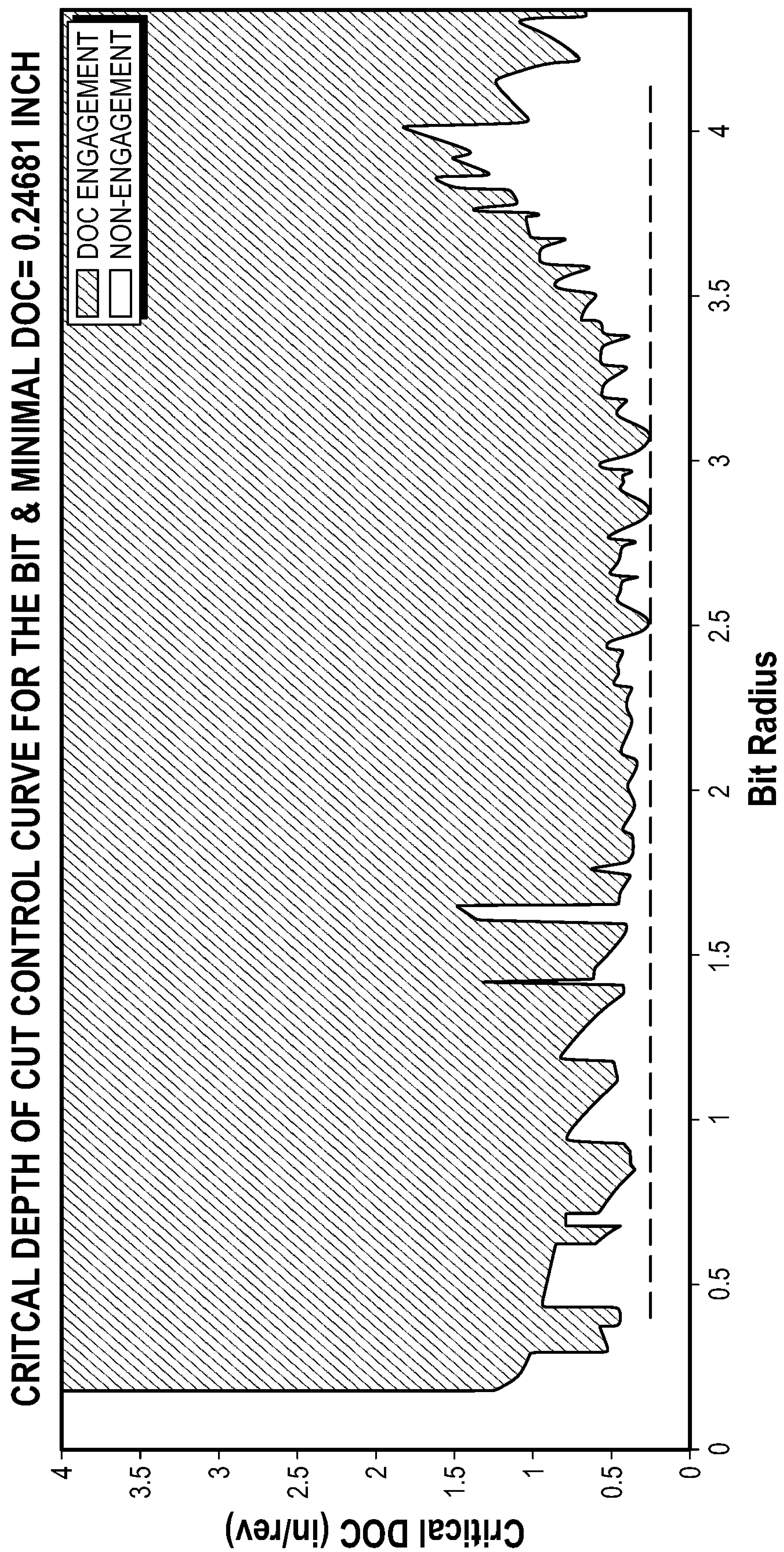

CRITCAL DEPTH OF CUT CONTROL CURVE FOR THE BIT & MINIMAL DOC= 0.24681 INCH
DOC ENGAGEMENT
NON-ENGAGEMENT
Critical DOC (in/rev)
0
0.5
1
1.5
2
2.5
3
3.5
4
Bit Radius
0
0.5
1
1.5
2
2.5
3
3.5
4

FIG. 9

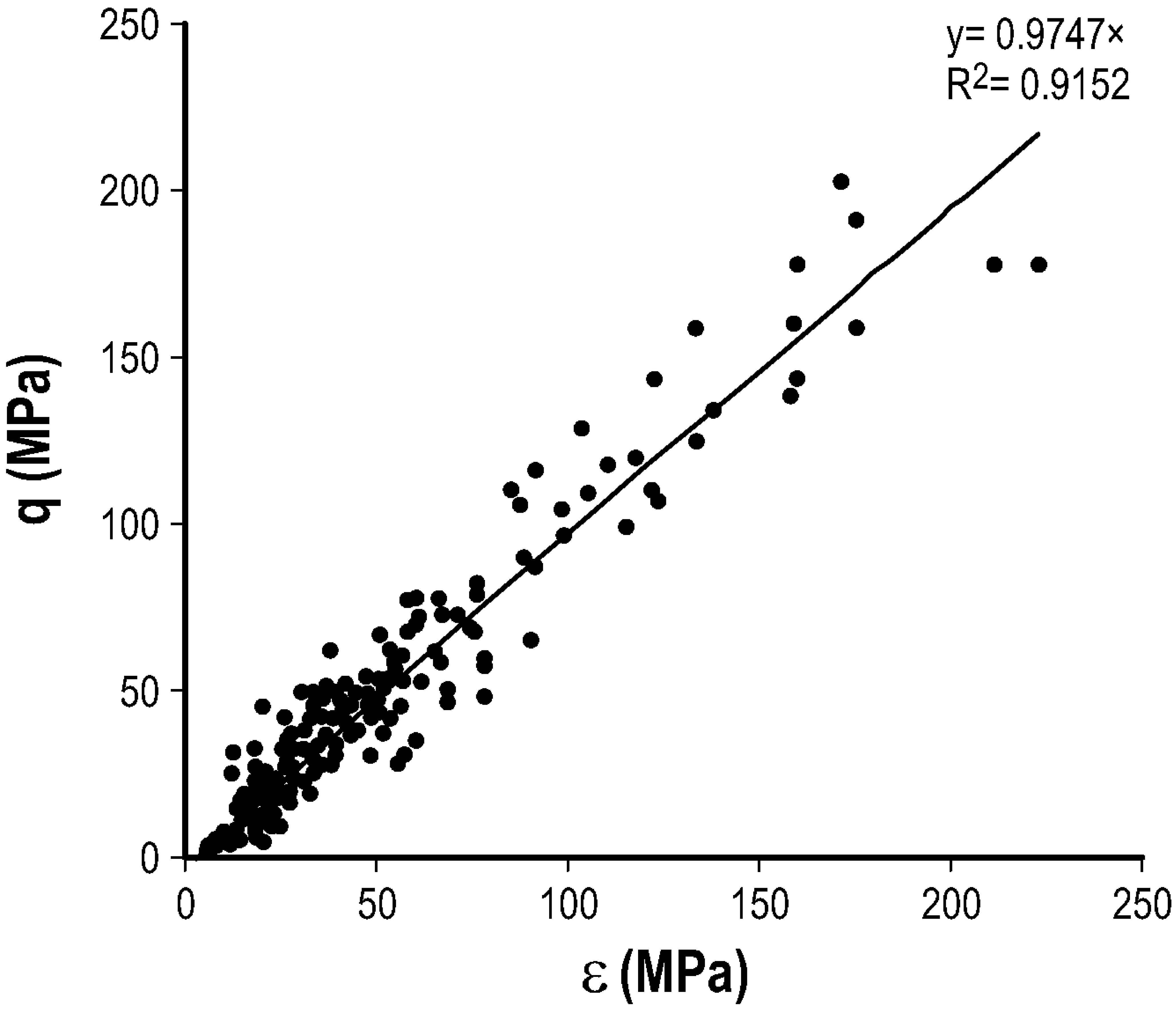
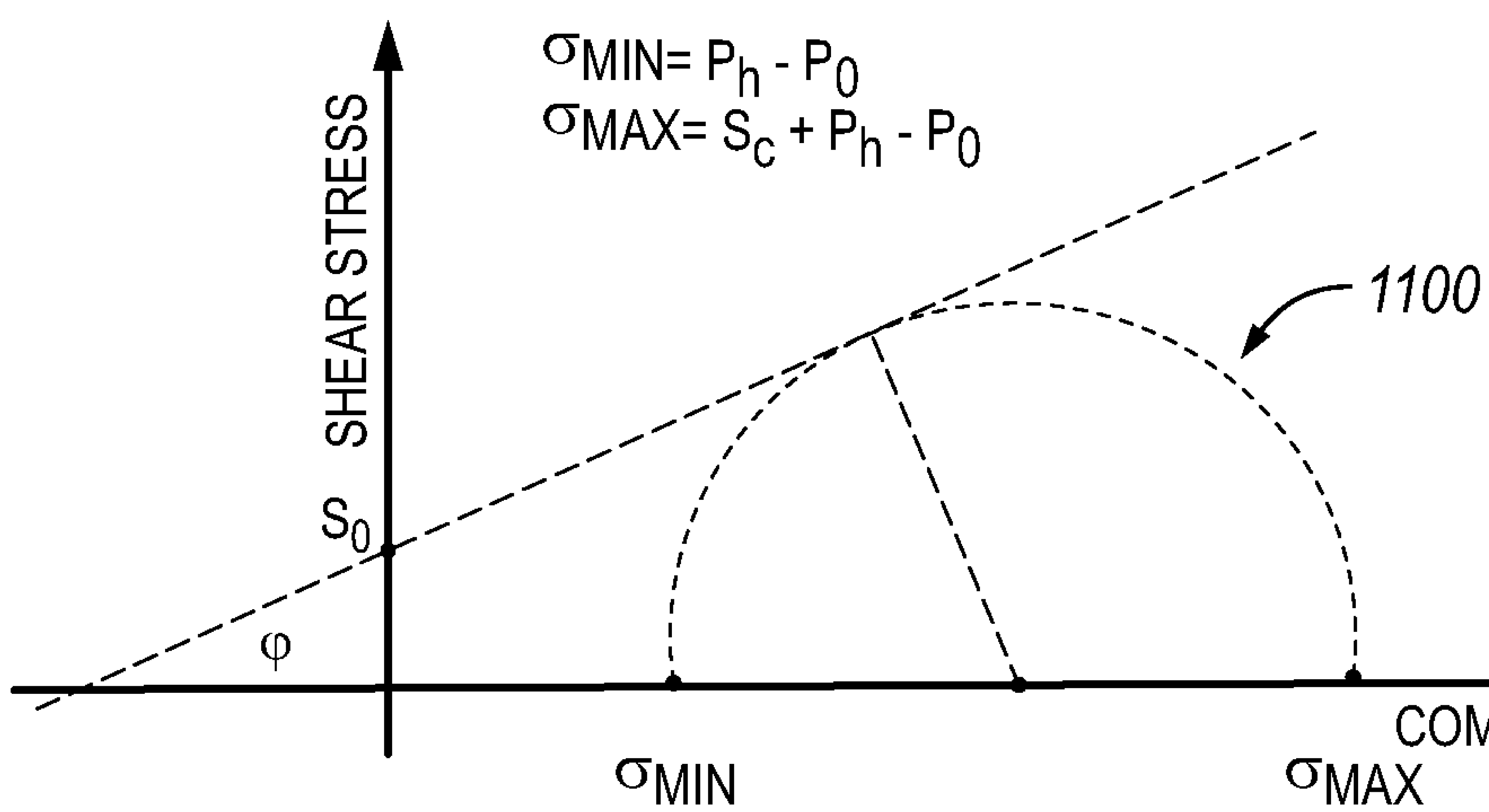


FIG. 10



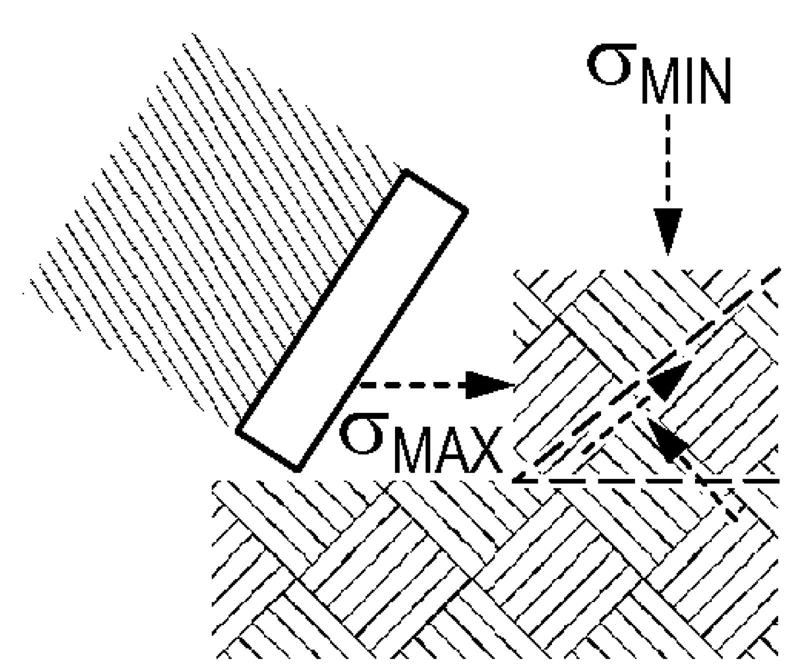


FIG. 11B

FIG. 11A

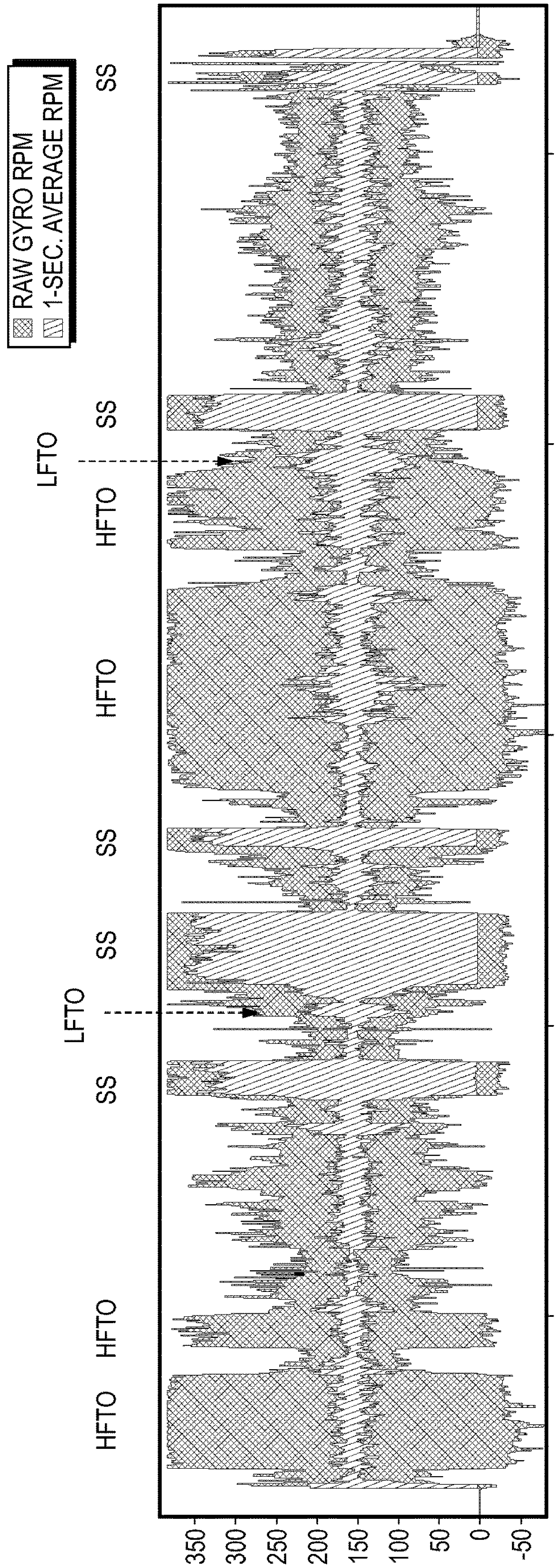

RAW GYRO RPM
1-SEC. AVERAGE RPM
SS
LFTO
SS
HFTO
HFTO
SS
SS
LFTO
SS
HFTO
HFTO
350
300
250
200
150
100
50
0
-50
JUN 05, 01:30
JUN 05, 01:00
JUN 05, 00:30
JUN 05, 00:00
JUN 04, 23:30

FIG. 12A

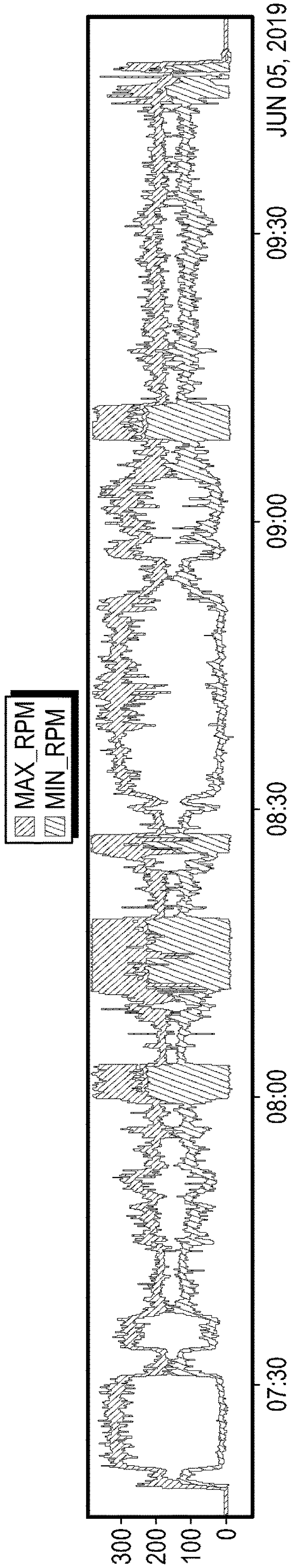


FIG. 12B

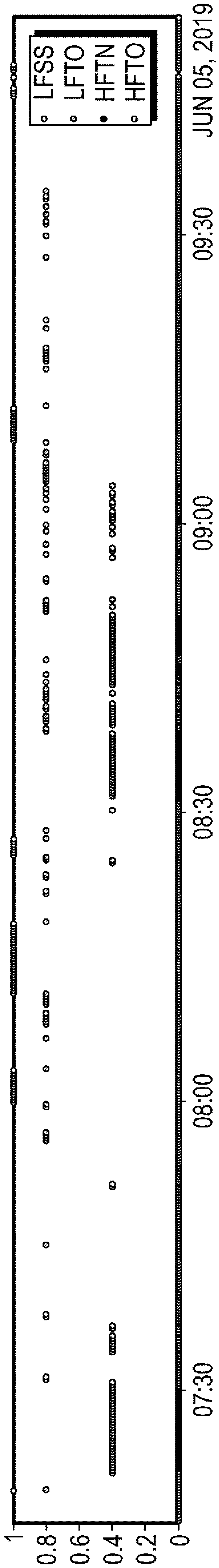


FIG. 12C

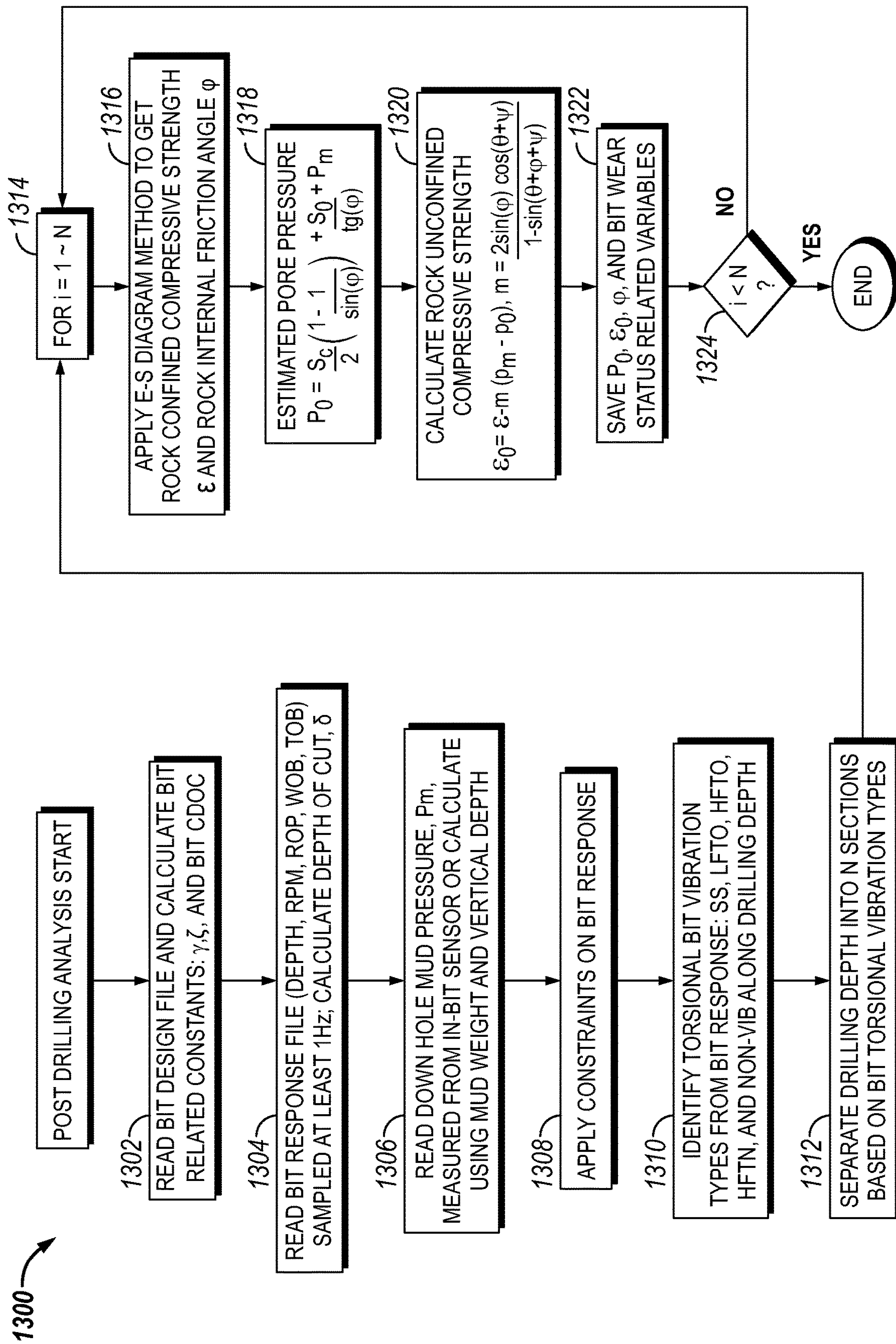

1300
POST DRILLING ANALYSIS START
1302
READ BIT DESIGN FILE AND CALCULATE BIT RELATED CONSTANTS: γ,ζ, AND BIT CDOC
1304
READ BIT RESPONSE FILE (DEPTH, RPM, ROP, WOB, TOB) SAMPLED AT LEAST 1Hz; CALCULATE DEPTH OF CUT, δ
1306
READ DOWN HOLE MUD PRESSURE, Pm, MEASURED FROM IN-BIT SENSOR OR CALCULATE USING MUD WEIGHT AND VERTICAL DEPTH
1308
APPLY CONSTRAINTS ON BIT RESPONSE
1310
IDENTIFY TORSIONAL BIT VIBRATION TYPES FROM BIT RESPONSE: SS, LFTO, HFTO, HFTN, AND NON-VIB ALONG DRILLING DEPTH
1312
SEPARATE DRILLING DEPTH INTO N SECTIONS BASED ON BIT TORSIONAL VIBRATION TYPES
1314
FOR i = 1 ~ N
1316
APPLY E-S DIAGRAM METHOD TO GET ROCK CONFINED COMPRESSIVE STRENGTH ε AND ROCK INTERNAL FRICTION ANGLE φ
1318
ESTIMATED PORE PRESSURE
$P_0 = \frac{S_c}{2}\left(1 - \frac{1}{\sin(\varphi)}\right) + \frac{S_0}{tg(\varphi)} + P_m$
1320
CALCULATE ROCK UNCONFINED COMPRESSIVE STRENGTH
$\varepsilon_0 = \varepsilon - m\,(p_m - p_0)$, $m = \frac{2\sin(\varphi)\cos(\theta+\psi)}{1-\sin(\theta+\varphi+\psi)}$
1322
SAVE P_0, ε_0, φ, AND BIT WEAR STATUS RELATED VARIABLES
1324
i < N ?
NO
YES
END

FIG. 13

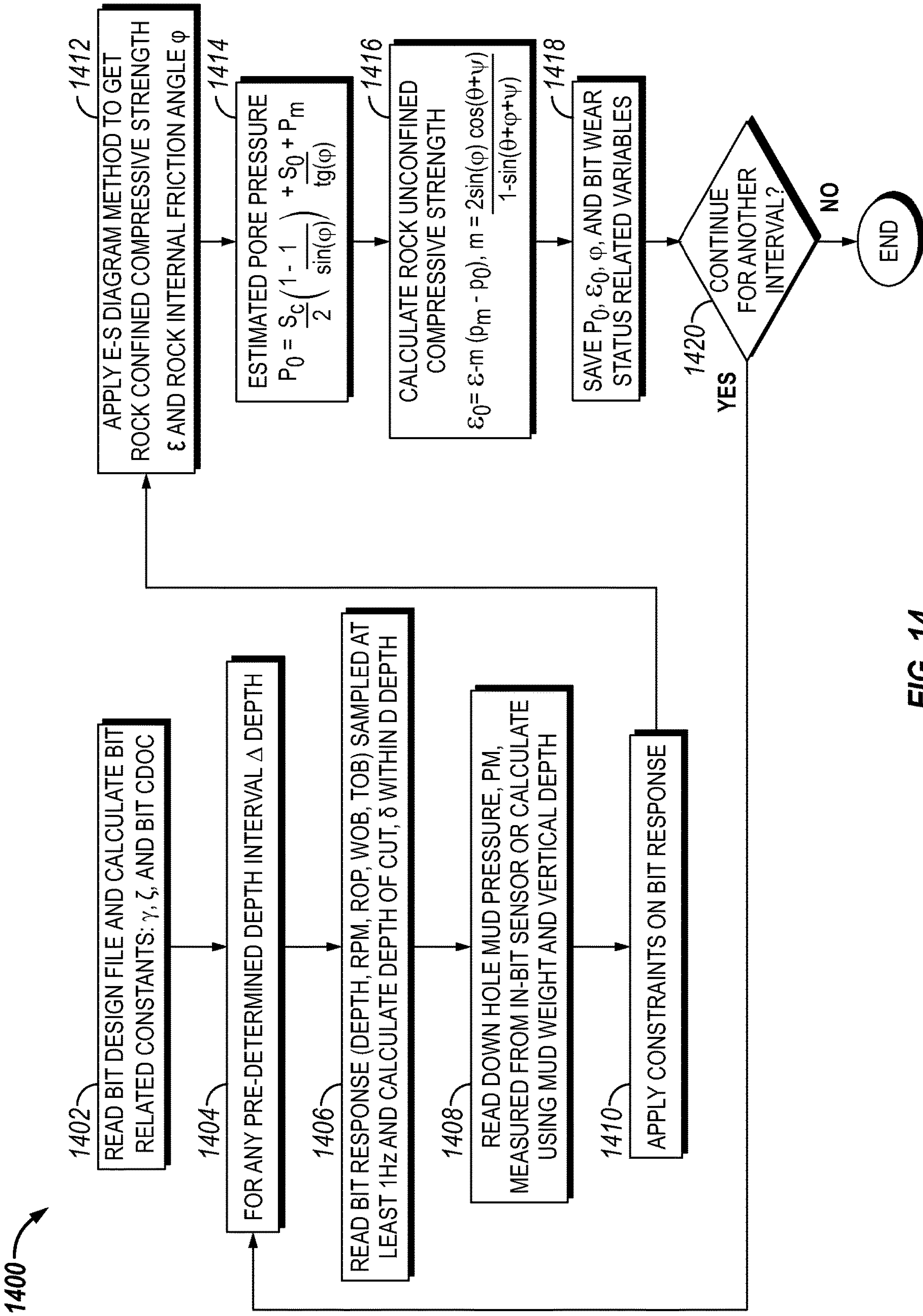

1400
1402
READ BIT DESIGN FILE AND CALCULATE BIT RELATED CONSTANTS: γ, ζ, AND BIT CDOC
1404
FOR ANY PRE-DETERMINED DEPTH INTERVAL Δ DEPTH
1406
READ BIT RESPONSE (DEPTH, RPM, ROP, WOB, TOB) SAMPLED AT LEAST 1Hz AND CALCULATE DEPTH OF CUT, δ WITHIN D DEPTH
1408
READ DOWN HOLE MUD PRESSURE, PM, MEASURED FROM IN-BIT SENSOR OR CALCULATE USING MUD WEIGHT AND VERTICAL DEPTH
1410
APPLY CONSTRAINTS ON BIT RESPONSE
1412
APPLY E-S DIAGRAM METHOD TO GET ROCK CONFINED COMPRESSIVE STRENGTH ε AND ROCK INTERNAL FRICTION ANGLE φ
1414
ESTIMATED PORE PRESSURE
$P_0 = \frac{S_c}{2}\left(\frac{1-1}{\sin(\varphi)}\right) + \frac{S_0}{tg(\varphi)} + P_m$
1416
CALCULATE ROCK UNCONFINED COMPRESSIVE STRENGTH
$\varepsilon_0 = \varepsilon - m\,(p_m - p_0)$, $m = \frac{2\sin(\varphi)\cos(\theta+\psi)}{1-\sin(\theta+\varphi+\psi)}$
1418
SAVE P_0, ε_0, φ, AND BIT WEAR STATUS RELATED VARIABLES
1420
CONTINUE FOR ANOTHER INTERVAL?
YES
NO
END

FIG. 14

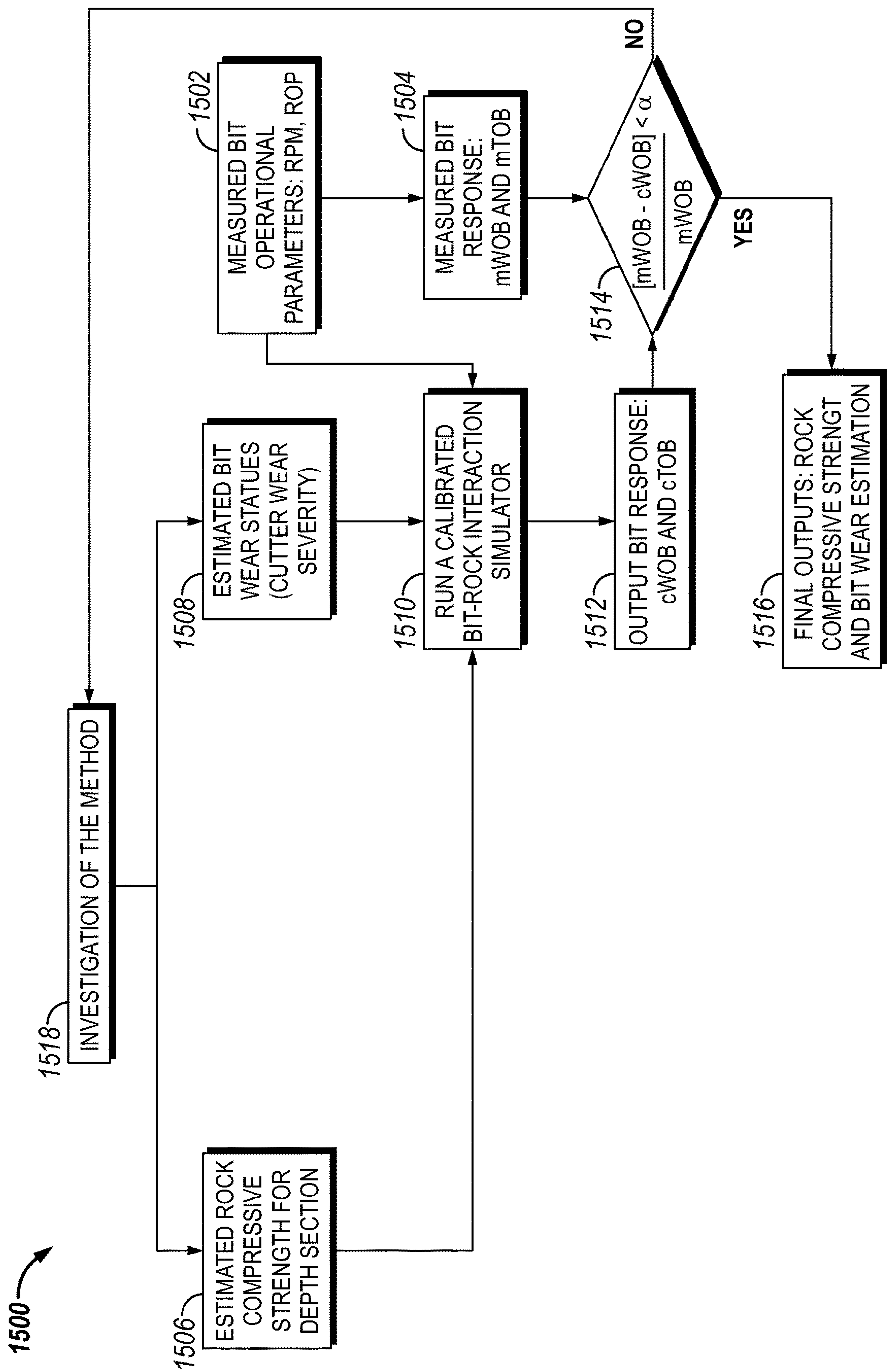

1500
1518
INVESTIGATION OF THE METHOD
1506
ESTIMATED ROCK COMPRESSIVE STRENGTH FOR DEPTH SECTION
1508
ESTIMATED BIT WEAR STATUES (CUTTER WEAR SEVERITY)
1502
MEASURED BIT OPERATIONAL PARAMETERS: RPM, ROP
1504
MEASURED BIT RESPONSE: mWOB AND mTOB
1510
RUN A CALIBRATED BIT-ROCK INTERACTION SIMULATOR
1512
OUTPUT BIT RESPONSE: cWOB AND cTOB
1514
[mWOB - cWOB] < α
mWOB
NO
YES
1516
FINAL OUTPUTS: ROCK COMPRESSIVE STRENGT AND BIT WEAR ESTIMATION

FIG. 15

MONITORING DRILLING CONDITIONS AND ESTIMATING ROCK PROPERTIES

BACKGROUND

Wells may be drilled into subterranean formations to recover natural deposits of hydrocarbons and other desirable materials trapped in geological formations in the Earth's crust.

Wells may be drilled by rotating a drill bit which may be located on a bottom hole assembly at a distal end of a drill string in a drilling operation.

Unconfined compressive strength (UCS) is one of the most commonly required rock mechanical properties in geomechanical assessments and in drilling and completion operations. However, reliable quantitative data on UCS may only be derived at specific depths from laboratory tests on core samples, typically through destructive tests or non-destructive tests under specified conditions. It is very hard to get UCS with high resolution as a continuous function along well depth. Additionally, it is hard to make a decision to pull out a bit when rate of penetration (ROP) is reduced in drilling because it is usually unclear if the reduction of ROP is due to bit wear or due to strong formation or due to both.

BRIEF DESCRIPTION OF THE DRAWINGS

These drawings illustrate certain aspects of some examples of the present disclosure and should not be used to limit or define the disclosure.

FIG. **1** illustrates an example of a drilling system;

FIG. **2** illustrates an example of a drill bit;

FIG. **3** illustrates a cross section view of the drill bit and location of a sensor package;

FIG. **4** illustrates two or more strain gauges connected together;

FIG. **5** illustrates angles of force utilized by a cutter on a formation;

FIG. **6** illustrates a force diagram of the cutter on the formation;

FIG. **7** illustrates a schematic of a cutter;

FIG. **8** illustrates the force diagram of FIG. **6** utilizing additional variables;

FIG. **9** is a graph showing depth of cut for a drill bit;

FIG. **10** is a graph showing a correlation between intrinsic specific energy and uniaxial compressive strength;

FIG. **11**A illustrates a Mohr circle;

FIG. **11**B illustrates angles of the cutter on virgin pores;

FIGS. **12**A-**12**C are graphs showing different types of torsional vibrations;

FIG. **13** is a workflow for post drill analysis of a drill bit performance during drilling operations;

FIG. **14** is a workflow for identifying bit wear during drilling operations in real time; and

FIG. **15** is a workflow for verifying rock confined compressive strength (CCS) and bit wear of the drill bit.

DETAILED DESCRIPTION

This disclosure may generally relate to methods for determining wear to a drill bit during drilling operations and if a reduction in rate of penetration (ROP) is due to bit wear or the formation. During drilling operation, a sensor package may measure revolutions per minute of the drill bit, weight on bit, and torque on bit and send these measurements to the surface in real time. In real time is defined as every second or every few seconds. Combining rate of penetration measurements at the surface with measurements taken by the sensor package downhole different types of torsional vibration may be identified. Additionally, the measurements may be divided into sections using the torsional vibration. Within each section, unconfined compressive strength (UCS), rock internal friction angle, bit wear, or cutter damage statues may be identified. Additionally, a bit-rock interaction model may be used to estimate the error ranges of the UCS at each bit wear statues. Friction energy as a function of drilling depth may also be utilized to determine a bit wear at depth during drilling operations.

FIG. **1** illustrates a drilling system **100** that may include a drill bit **102** undergoing drilling operations. It should be noted that while FIG. **1** generally depicts drilling system **100** in the form of a land-based system, those skilled in the art will readily recognize that the principles described herein are equally applicable to subsea drilling operations that employ floating or sea-based platforms and rigs, without departing from the scope of the disclosure.

Drilling system **100** may include a drilling platform **104** that supports a derrick **106** having a traveling block **108** for raising and lowering a drill string **110**. A kelly **112** may support drill string **110** as drill string **110** may be lowered through a rotary table **114**. Drill string **110** may include a drill bit **102** attached to the distal end of drill string **110** and may be driven either by a downhole mud motor **116**, discussed below, and/or via rotation of drill string **110**. Without limitation, drill string **110** may include any suitable type of drill bit **102**, including, but not limited to, roller cone bits, fixed cutter bits, PDC bits, natural diamond bits, any hole openers, reamers, coring bits, and the like. As drill bit **102** rotates, drill bit **102** may create a borehole **118** that penetrates various formations **120**.

The rotation of drill bit **102** may be controlled by mud motor **116**. In examples, mud motor **116** may allow for directionally steering within borehole **118** and may deliver additional energy to drill bit **102** to improve drilling performance. Mud motor **116** may deliver additional power to drill bit **102** by converting fluid energy from the drilling fluid **128**, to mechanical rotation of a drill bit shaft in at least a portion of mud motor **116**. The conversion of fluid energy to mechanical rotation may be performed by an elastomeric stator within which a metallic rotor rotates as fluid is pumped through it. The speed with which the mud motor **116** rotates drill bit **102** is a function of the mud flow rate and the design or configuration of a particular stator and rotor within a mud motor power section. Likewise, the torque applied to drill bit **102** is a function of the differential pressure across the mud motor power section and the design of mud motor **116**.

Drilling system **100** may further include a mud pump **122**, one or more solids control systems **124**, and a retention pit **126**. Mud pump **122** representatively may include any conduits, pipelines, trucks, tubulars, and/or pipes used to fluidically convey drilling fluid **128** downhole, any pumps, compressors, or motors (e.g., topside or downhole) used to drive the drilling fluid **128** into motion, any valves or related joints used to regulate the pressure or flow rate of drilling fluid **128**, any sensors (e.g., pressure, temperature, flow rate, etc.), gauges, and/or combinations thereof, and the like.

Mud pump **122** may circulate drilling fluid **128** through a feed conduit **130** and to kelly **112**, which may convey drilling fluid **128** downhole through the interior of drill string **110** and through one or more orifices (not shown) in drill bit **102**. Drilling fluid **128** may then be circulated back to surface **134** via a borehole annulus **160** defined between drill string **110** and the walls of borehole **118**. At surface **134**, the recirculated or spent drilling fluid **128** may exit borehole annulus **160** and may be conveyed to one or more solids control system **124** via an interconnecting flow line **132**. One or more solids control systems **124** may include, but are not limited to, one or more of a shaker (e.g., shale shaker), a centrifuge, a hydrocyclone, a separator (including magnetic and electrical separators), a desilter, a desander, a separator, a filter (e.g., diatomaceous earth filters), a heat exchanger, and/or any fluid reclamation equipment. The one or more solids control systems **124** may further include one or more sensors, gauges, pumps, compressors, and the like used to store, monitor, regulate, and/or recondition the drilling fluid **128**.

After passing through the one or more solids control systems **124**, drilling fluid **128** may be deposited into a retention pit **126** (e.g., a mud pit). While illustrated as being arranged at the outlet of borehole **118** via borehole annulus **160**, the one or more solids controls system **124** may be arranged at any other location in drilling system **100** to facilitate its proper function, without departing from the scope of the disclosure. While FIG. **1** shows only a single retention pit **126**, there could be more than one retention pit **126**, such as multiple retention pits **126** in series. Moreover, retention pit **126** may be representative of one or more fluid storage facilities and/or units where the drilling fluid additives may be stored, reconditioned, and/or regulated until added to drilling fluid **128**.

Drilling system **100** may further include information handling system **140** configured for processing the measurements from sensors (where present), such as sensor package **224**, discussed below, disposed on drill bit **102**. Measurements taken may be transmitted to information handling system **140** by communication module **138**. As illustrated, information handling system **140** may be disposed at surface **134**. In examples, information handling system **140** may be disposed downhole. Any suitable technique may be used for transmitting signals from communication module **138** to information handling system **140**. A communication link **150** (which may be wired, wireless, or combinations thereof, for example) may be provided that may transmit data from communication module **138** to information handling system **140**. Without limitation, information handling system **140** may include any instrumentality or aggregate of instrumentalities operable to compute, classify, process, transmit, receive, retrieve, originate, switch, store, display, manifest, detect, record, reproduce, handle, or utilize any form of information, intelligence, or data for business, scientific, control, or other purposes. For example, information handling system **140** may be a personal computer, a network storage device, or any other suitable device and may vary in size, shape, performance, functionality, and price. Information handling system **140** may include random access memory (RAM), one or more processing resources (e.g., a microprocessor) such as a central processing unit **142** (CPU) or hardware or software control logic, ROM, and/or other types of nonvolatile memory. Additional components of information handling system **140** may include one or more monitors **144**, an input device **146** (e.g., keyboard, mouse, etc.) as well as computer media **148** (e.g., optical disks, magnetic disks) that may store code representative of the methods described herein. Information handling system **140** may also include one or more buses (not shown) operable to transmit communications between the various hardware components.

In examples, information handling system **140** may be utilized to improve mud motor **116** construction while mud motor **116** may be utilized during drilling operations. For example, currently mud motor manufacturers commonly publish reference charts which plot the nominal speed and torque output of mud motor **116** with different combinations of flow rate and differential pressure. In practice, these nominal values vary due to mud properties, temperature, dimensional fit (e.g., clearance or interference) between the rotor and stator and the physical condition of mud motor **116**. Before utilizing mud motor **116** during drilling operations, mud motor **116** may be placed in a surface dynamometer where a working fluid, usually water, is pumped through the motor and the output (e.g., torque and shaft speed) of the motor is measured and compared against the nominal power curve provided by the manufacturer. Such tests are also performed as a proof test to screen out mud motors **116** which may have infantile failures in the wellbore due to an assembly defect. However, in practice, surface dynamometers are rarely used. Currently, dynamometers may not be used due to the additional time and expense required to perform the test, availability of dynamometers, inability to replicate downhole conditions (i.e., downhole pressure and temperature), and inability to replicate drilling fluid properties.

FIG. **2** illustrates an example of drill bit **102** known as a fixed cutter bit. Without limitation, drill bit **102** may be applied to any fixed cutter drill bit category, including polycrystalline diamond compact (PDC) drill bits, sometimes referred to as drag bits, and which can be, for example, matrix drill bits and/or steel body drill bits depending on the composition and manufacture of the bit body. While drill bit **102** is depicted as a fixed cutter drill bit, the principles of the present disclosure are equally applicable to other types of drill bits operable to form a wellbore including, but not limited to, fixed cutter core bits, impregnated diamond bits and roller cone drill bits.

With continued reference to FIG. **2**, drill bit **102** includes a bit body **200** of drill bit **102** which may include radially and longitudinally extending blades **202** having leading faces **204**. Bit body **200** may be made of steel or a matrix of a harder material, such as tungsten carbide Bit body **200** rotates about a longitudinal drill bit axis **206** to drill into underlying subterranean formation under an applied weight-on-bit. Corresponding junk slots **208** are defined between circumferentially adjacent blades **202**, and a plurality of nozzles or ports **210** may be arranged within junk slots **208** for ejecting drilling fluid that cools drill bit **102** and otherwise flushes away cuttings and debris generated while drilling.

Bit body **200** further includes a plurality of fixed cutters **212** secured within a corresponding plurality of cutter pockets sized and shaped to receive fixed cutters **212**. Each fixed cutter **212** in this example comprises a fixed cutter secured within its corresponding cutter pocket via brazing, threading, shrink-fitting, press-fitting, snap rings, or any combination thereof. Fixed cutters **212** are held in blades **202** and respective cutter pockets at predetermined angular orientations and radial locations to present fixed cutters **212** at an angle against the formation being penetrated. As drill bit **102** is rotated, fixed cutters **212** are driven through the formation by the combined forces of the weight-on-bit and the torque experienced at drill bit **102** During drilling, fixed cutters **212** may experience a variety of forces, such as drag forces, axial forces, reactive moment forces, or the like, due to the interaction with the underlying formation being drilled as drill bit **102** rotates.

Each fixed cutter **212** may include a generally cylindrical substrate **220** made of an extremely hard material, such as tungsten carbide, and a cutting face **222** secured to the substrate **220**. The cutting face **222** may include one or more layers of an ultra-hard material, such as polycrystalline diamond, polycrystalline cubic boron nitride, impregnated diamond, etc., which generally forms a cutting edge and the working surface for each fixed cutter **212**. The working surface is typically flat or planar but may also exhibit a curved exposed surface that meets the side surface at a cutting edge.

Generally, each fixed cutter **212** may be manufactured using tungsten carbide as the substrate **220**. While a cylindrical tungsten carbide "blank" may be used as the substrate **220**, which is sufficiently long to act as a mounting stud for the cutting face **222**, the substrate **220** may equally comprise an intermediate layer bonded at another interface to another metallic mounting stud. To form the cutting face **222**, the substrate **220** may be placed adjacent a layer of ultra-hard material particles, such as diamond or cubic boron nitride particles, and the combination is subjected to high temperature at a pressure where the ultra-hard material particles are thermodynamically stable. This results in recrystallization and formation of a polycrystalline ultra-hard material layer, such as a polycrystalline diamond or polycrystalline cubic boron nitride layer, directly onto the tipper surface of the substrate **220**. When using polycrystalline diamond as the ultra-hard material, fixed cutter **212** may be referred to as a polycrystalline diamond compact cutter or a "PDC cutter," and drill bits made using such PDC fixed cutters are generally known as PDC bits.

As illustrated, drill bit **102** may further include a plurality of rolling element assemblies **214**, each including a rolling element **216** disposed in housing **218**. Housing **218** may be received in a housing pocket sized and shaped to receive housing **218**. Without limitation, rolling element **216** may include a generally cylindrical body strategically positioned in a predetermined position and orientation on bit body **200** so that rolling element **216** is able to engage the formation during drilling. It should be noted that rolling element **216** may also be a ball bearing, cylindrical, needle, tapered, and/or circular in shape. The orientation of a rotational axis of each rolling element **216** with respect to a direction of rotation of a corresponding blade **202** may dictate whether any identified rolling element **216** operates purely as a rolling DOCC element, purely a rolling cutting element, or a hybrid of both. The terms "rolling element" and "rolling DOCC element" are used herein to describe the rolling element **216** in any orientation, whether it acts purely as a DOCC element, purely as cutting element, or as a hybrid of both. Rolling elements **216** may prove advantageous in allowing for additional weight-on-bit (WOB) to enhance directional drilling applications without over engagement of fixed cutters **212**, and to minimize the amount of torque required for drilling Effective DOCC also limits fluctuations in torque and minimizes stick-slip, which may cause damage to fixed cutters **212**. An optimized three-dimensional position and three-dimensional orientation of rolling element **216** may be selected to extend the life of the rolling element assemblies **214**, and thereby improve the efficiency of drill bit **102** over its operational life. As described herein, the three-dimensional position and orientation may be expressed in terms of a Cartesian coordinate system with the Y-axis positioned along longitudinal axis **206**, and a polar coordinate system with a polar axis positioned along longitudinal axis **206**. Without limitation, drill bit **102** may include a sensor package **224**, further discussed below.

FIG. **3** illustrates a cross sectional view of a removable sensor package **224** disposed in a drill bit **102**. In other examples, sensor package **224** may be non-removable. As illustrated in FIG. **3**, there are two sensor package **224** is disposed in a shank **300** of drill bit **102**. However, there may be any number of measurement devices that measure different vibration within sensor package **224** disposed in shank **300**. As illustrated, sensor packages **224** may be an insert with a puck like design. Each sensor package **224** is disposed approximately 180 degrees from one another within recessed areas **302**. Recessed area **302** may be disposed on the exterior of shank **300**. In examples, sensor package **224** may be held in recessed areas **302** through threading, compression, and/or the like. In one example, one or more sensor packages **224** may be disposed within one or more junk slots and/or fluid flow paths of drill bit **102**. For example, one or more sensor packages **224** may be positioned such that downhole forces applied to junk slots and/or fluid flow paths may be similarly applied to one or more sensor packages **224** and, in turn, to the sensor packages **224** disposed thereon.

FIG. **4** illustrates an example wherein sensor packages are disposed in the shank **300** of the drill bit **102** approximately 180 degrees from one another and within the recessed area **302**, may be interconnected. Shank **300** may include a bore **400** extending through shank **300** between sensor packages **224**. Sensor packages **224** may be interconnected via a hardwire connection **402** extending between sensor packages **224** and through bore **400**. Interconnecting sensor packages **224** may allow for improved packaging of sensor packages **224** with various downhole components (e.g., accelerometers, magnetometers, processors, batteries, etc.). Further, regarding positioning of sensor packages **224**, interconnecting sensor packages **224** may allow sensor packages **224** to be spread further apart than non-interconnected strain gauges, which may improve measurement resolution. In another example, one or more sensor packages **224** may be disposed on one or more blades of drill bit **102** such that downhole forces applied to each of the one or more blades **202** (e.g., referring to FIG. **2**) may be similarly applied to sensor packages **224** and to the strain gauges disposed thereon. In each of the examples described above, sensor packages **224** may include transmitters used to transmit data indicating downhole forces to one or more receivers such that the data from each sensor packages **224** may be analyzed.

Referring back to FIG. **3**, each sensor package **224** may collect data indicating downhole forces applied to drill bit **102** during a drilling operation. In particular, downhole forces applied to shank **300** of drill bit **102** may be similarly applied to each sensor package **224**. In examples, sensor package **224** may transmit data indicating downhole forces to one or more receivers such that the data from each sensor package **224** may be analyzed. Specifically, sensor package **224** may collect data indicating compression forces, bending forces, and torsional forces applied to each sensor package **224** during a drilling operation and may transmit the collected data in real-time. This data may be received by a receiver for real-time analysis or stored in a memory medium within drill bit **102** for analysis at a later time.

Analysis of data received from sensor package **224** by information handling system **140** (e.g., referring to FIG. **1**) may suggest ways in which one or more downhole drilling parameters may be modified to reduce the magnitude of the downhole forces applied to drill bit **102**. Examples of the downhole drilling parameters may include rotational speed of drill bit **102** in revolutions per minute (RPM), a rate of penetration (ROP), a weight on bit (WOB), a torque on bit (TOB), and a depth-of-cut (DOC). The rate of penetration (ROP) of drill bit **102** may be a function of both weight on bit (WOB) and revolutions per minute (RPM). Referring back to FIG. **1**, drill string **110** may apply weight on drill bit **102** and may also rotate drill bit **102** about a rotational axis to form borehole **118**. The depth-of-cut per revolution may also be based on ROP and RPM of a particular bit and indicates how deeply the cutting elements (e.g., referring to FIG. **2**) may be engaging the formation. An analysis of the data received from sensor package **224** may indicate which of the downhole drilling parameters may be causing or contributing to compression forces, bending forces, and/or torsional forces applied to sensor package **224** during drilling operations.

Additionally, sensor packages **224** may be disposed approximately 180 degrees from one another, data received from strain gauges disposed on each sensor package **224** may be used simultaneously for analysis to determine downhole forces being applied to both sides of shank **300** (e.g., compression or bending). In examples, data indicating compression forces applied to both sensor package **224** may be analyzed to calculate the weight on bit (WOB) based on a compression value from either sensor package **224** or a compression value from the other sensor package **224**.

In other examples, a bending value may be calculated based on a compression value from one sensor package **224** and a tension value (i.e., indicating a tensile force) from the other sensor package **224**. In yet another examples, a torque on bit (TOB) value may be calculated based on torsion value (i.e., indicating a torsional force) applied to both sensor packages **224**. In another example, drill bit **102** may include three sensor package **224** disposed 120 degrees from one another. In yet another example, drill bit **102** may include four sensor packages **224** disposed 90 degrees from one another. In each of these examples, data received from sensor package **224** may be used simultaneously for analysis to determine downhole forces being applied to shank **300**, for example, to identify a direction of a bending force and/or to determine whether a torsional force is symmetric around shank **300**.

Values indicating WOB, bending, and TOB may be used to determine a set of optimized downhole drilling parameters in order to extend the lifetime of the downhole drilling tool and/or perform more efficient drilling operations. In particular, if WOB exceeds an adjustable threshold, compression forces applied to the downhole drilling tool may damage the downhole drilling tool or result in inefficient drilling operations. Accordingly, WOB may be modified such that WOB is within the adjustable threshold. Similarly, if a bending value exceeds an adjustable threshold, bending forces may damage the downhole drilling tool or drill string **110** (e.g., referring to FIG. **1**) of drilling system **100** (e.g., referring to FIG. **1**). In response, the bending value may be modified such that the bending value is within the adjustable threshold, thereby reducing the bending forces applied to the downhole drilling tool. Lastly, if TOB exceeds an adjustable threshold, the TOB may be modified such that the TOB value is within the adjustable threshold, thereby reducing torsional forces applied to the downhole drilling tool. Additionally, if WOB, bending, and TOB values are determined to be within only a fraction (e.g., 25 percent) of each corresponding adjustable threshold, downhole drilling parameters may be modified to increase compression forces (i.e., WOB), bending forces, and torsional forces (i.e., TOB) such that the modified downhole drilling parameters may result in more efficient drilling operations.

As discussed above, sensor package **224** may take downhole measurements of forces applied to drill bit **102**. These parameters may be weight on bit, torque on bit, inner pressure, outer pressure, rotational speed, and/or the like. In examples, parameters that may be measured may be transmitted to the information handling system **140** to be processed with surface characteristics that are taken at drilling platform **104**. Without limitation, surface data may be pipe rotation rate, flow rate, differential pressure, and/or the like. The information handling system **140** may receive the surface data from sensors disposed proximate the drilling platform **104** (e.g., referring to FIG. **1**) or from another source. Utilizing parameters measured downhole and surface data, information handling system **140** may be utilized to determine unconfined compressive strength (UCS).

Identifying UCS may allow for bit wear to be determined in real time during drilling operations or after drilling operations.

Bit wear may be determined by identifying the action of a single fixed cutter **212** on formation **120**. FIG. **5** is an illustration of fixed cutter **212** asserting a force on formation **120** through mathematical equations. Cutting forces exerted on formation **120** by fixed cutter **212** may be described as:

$$F_s^c = \varepsilon w d \tag{1}$$

$$F_n^c = \zeta \varepsilon w d, \text{ where } \zeta = \tan(\theta + \psi) \tag{2}$$

where ε is intrinsic specific energy, w is cutter wear width, and d is depth of cut. Additionally, ζ is a cutting force inclination coefficient. Friction for a dull cutter is described as:

$$F_s^f = \mu F_n^f \tag{3}$$

where p is a friction coefficient. Additionally governing Equations may also be used:

$$F_n = F_n^c + F_n^f \tag{4}$$

$$F_s = (1 - \mu\zeta)\varepsilon w d + \mu F_n \tag{5}$$

$$E = \frac{F_s}{wd} \tag{6}$$

$$S = \frac{F_n}{wd} \tag{7}$$

$$E = E_0 + \mu S \tag{8}$$

$$E_0 = (1 - \mu\zeta)\varepsilon \tag{9}$$

Equation (9) is applied to a single fixed cutter **212** for a single cutter test in which single fixed cutter **212** cuts into a rock, which may allow rock properties to be measured. For a PDC drill bit **102**, specific energy (E) and drilling strength (S) are defined respectively:

$$E = \frac{2TOB}{a^2\delta} \tag{10}$$

$$S = \frac{WOB}{a\delta} \tag{11}$$

$$\delta = \frac{ROP}{5RPM} \tag{12}$$

For sharp drill bit **102**:

$$E = \frac{1}{\zeta} S \tag{13}$$

For a worn drill bit **102**:

$$E=E_0+\mu\gamma S \quad (14)$$

In equation (12), ROP is rate of penetration per hour (ft/hr), RPM is bit rotational speed (rpm) and δ has unit of inch/rev.

FIG. **6** is a graph that may be utilized to solve for the variables that may be used for Equations (1)-(14) above. Using the graph in FIG. **6**, variables μ, ψ, ζ, ε may be found. Additionally, the variable ε_0 may be found using:

$$\varepsilon_0 = \frac{E_0}{1-\mu\zeta} \quad (15)$$

It is also noted that ψ is the PDC/rock friction angle and may depend only on Polycrystalline diamond compact (PDC) material and type of rock that drill bit **102** may be encountering within formation **120** during drilling operations, and ζ may depend on ψ and cutter back rake angle θ, using Equation (2). Additionally, μ may be internal friction angle of rock, which may depend only on type of rock and E^f is energy dissipated in friction.

As noted above, two additional parameters are determined. The cutting force inclination coefficient and the bit constant. Current technology makes assumptions regarding these two variables. However, these two variables are found utilizing mathematical formulations. For example, cutting force inclination coefficient ζ is found using Equation (2). As noted above, for a PDC cutter **212** (e.g., referring to FIG. **5**), θ is the back rake angle. For a PDC drill bit **102** (e.g., referring to FIG. **1**), θ is the average back rake angle of face PDC cutters **212**. Additionally, ψ is the friction angle between cutter face and rock surface, usually, ψ may be approximately 15 to 25 degrees. Further, bit constant γ, is found by:

$$\gamma = \frac{2\sum_i b_i p_i^L}{a\sum_i b_i} \quad (16)$$

Using FIG. **7**, variables for Equation (16) may be found. For example, α is bit radius, b_i is the length of the cutting edge projected in radial axis, p_i^L is the centroid radial-coordinate of the cutting edge; and p_i is the centroid location of the engagement surface.

Using the graph in FIG. **8**, confined compressive strength (CCS) is found by implementing:

$$\varepsilon = \frac{E_0}{1-\mu\gamma\zeta} = \frac{E_0}{1-\beta}, \text{ where } \beta < 1 \quad (17)$$

The increase of ζ may increase e. Additionally, the rock internal friction angle may be found using the graph in FIG. **8** and

$$\psi = a\tan(\mu) \quad (18)$$

Additionally, fiction energy is identified by the variable E^f, for bit wear. With continued use of the graph in FIG. **8**, contact force (λσ) may be found using:

$$\lambda\sigma = \frac{\delta(E-\varepsilon)}{\mu\gamma} \quad (19)$$

Use of the graph in FIG. **8** may allow for relative contact length to be found using:

$$\lambda = \frac{\delta(E-\varepsilon)}{\mu\gamma\varepsilon} \quad (20)$$

Which provides a measure of the bit wear state. Drilling efficiency may also be found using;

$$\eta = \frac{X-\mu\gamma}{(1-\mu\gamma\omega)\chi} \quad (21)$$

where

$$\chi = \frac{E}{S} \quad (22)$$

It should be noted, in Equations (16)-(22) and graphs in FIGS. **7** and **8** above, only cutter forces (cutting force and friction force from cutters) are considered. However, any bladed Polycrystalline Diamond Compact (PDC) bit (i.e., drill bit **102**) has a blade surface which may contact formation when depth of cut is large enough. The forces due to blade surface contact may be contributed to the measured wight on bit (WOB) and torque on bit (TOB). In addition, most of PDC bits have non-cutting elements such as depth of cut controllers. These non-cutting elements may be in contact with formation. The forces due to the contact may also be contributed to the measured WOB and TOB. This is illustrated in FIG. **9**, where the graph shows that when an instant depth of cut is over 0.24681 in/rev, the associated point in bit response is not utilized for the calculations discussed above.

Referring back to the graph in FIG. **8**, if $E_i>E_{max}$ and $S_i>S_{max}$ the measurements may be disregarded. If $E_i<E_{min}$ and $S_i<S_{min}$, the measurements may be disregarded. If $E_0<0$, the measurements may be disregarded. If $\beta=\mu\lambda\zeta>1$ the measurements may be disregarded. If $\varphi=a\tan(\mu)<5$ deg, the measurements may be disregarded. If $E_i<\varepsilon$, disregard the point (ε_0).

Unconfined compressive strength (UCS) is related to intrinsic specific energy (ε_0). Additionally, intrinsic specific energy may be related to pore pressure using the following Equations:

$$\varepsilon = \varepsilon_0 + m(p_m - p_0) \quad (23)$$

$$m = \frac{2\sin(\varphi)\cos(\theta+\psi)}{1-\sin(\theta+\varphi+\psi)} = 3 \sim 25 \quad (24)$$

where p_m is hole bottom pressure, p_0 is rock pore pressure, ε_0 is intrinsic specific energy and e is specific energy, which may be found using the Equations and methods above. Further

$$P_m = (mud\ \text{weight}+0.3)\times 0.052\times TVD(psi) \quad (25)$$

Additionally, φ=a tan(μ) and is rock internal friction angle, ψ is friction angle at the cutting face/failed rock interface, and θ is a cutter back rake angle. Further, these variables may be related as:

$$\theta+\psi = a\tan(\zeta) \quad (26)$$

Under atmospheric conditions:

$$P_m=P_0=0 \tag{27}$$

$$\varepsilon=\varepsilon_0 \tag{28}$$

For highly permeable rock:

$$P_m=P_0 \tag{29}$$

$$\varepsilon=\varepsilon_0 \tag{30}$$

For highly impermeable rock:

$$p_0=0 \tag{31}$$

$$\varepsilon=\varepsilon_0+m(p_m-p_0) \tag{32}$$

For sedimentary rocks:

$$\varepsilon=\varepsilon_0+m(p_m-p_0) \tag{33}$$

FIG. **1θ** is a graph illustrating the correlation between ε_0 and UCS for a variety of rocks. From this graph a linear progression is seen between ε_0 and UCS depending on the rock interface.

Additionally, FIGS. **11**A and **11**B illustrate virgin pore pressure estimation. As illustrated, a Mohr circle **1100** represents cutting stress, bottom hole pressure, and pore pressure. This may be mathematical represented as:

$$\sigma_{min}=P_h-P_O \tag{34}$$

$$\sigma_{max}=S_c+P_h-P_0 \tag{35}$$

Additionally, virgin proper pressure estimation may be found by utilizing:

$$P_0=\frac{S_c}{2}\left(1-\frac{1}{\sin(\varphi)}\right)+\frac{S_0}{tg(\varphi)}+P_m \tag{36}$$

$$S_c=\frac{2TOB}{a^2\delta}(\text{specific energy}) \tag{37}$$

$$S_0=\frac{\varepsilon_0(1-\sin(\varphi))}{2\cos(\varphi)} \tag{38}$$

where S_0 is cohesion, P_m is hole bottom pressure (See Equation (25)), and φ is rock internal friction angle. Additionally, revolutions per minute (RPM), rate of penetration (ROP), and torque on bit (TOB) may be found using sensor package **224** (e.g., referring to FIG. **2**), discussed above.

Sensor package **224** (e.g., referring to FIG. **2**) may be utilized to identify four types of torsional vibrations. The four types of torsional vibrations are stick-slip vibration (SS), low frequency torsional oscillation (LFTO), high frequency torsional oscillation (HFTO), and high frequency torsional noise (HFTN). Each lithology layer is associated with a type of torsional vibration. As illustrated in FIGS. **12**A-**12**C, identifying SS, LFTO, HFTO, HFTN, and where no dysfunction is measured identifies different layers within formation **120** (e.g., referring to FIG. **1**).

FIG. **13** illustrates workflow **1300** for post drill analysis of drill bit **102** (e.g., referring to FIG. **1**) performance during drilling operations. Workflow **1300** may begin with block **1302** in which constants for drill bit **102**, such as ζ, γ, and critical depth of cut (CDOC) are found utilizing the methods and Equations discussed above. After determining constants of drill bit **102**, a depth of cut is calculated, represented as δ, using measurements taken by sensor package **224** (e.g., referring to FIG. **2**) on drill bit **102**. In block **1304**, measurements taken may comprise depth, revolutions per minute (RPM), rate of penetration (ROP), weight on bit (WOB), and torque on bit (TOB) all sampled at least at 1 Hz. Additionally, in block **1306**, downhole mud pressure, P_m, measured by sensor package **224** on drill bit **102** are recovered or calculated using mud weight and vertical depth values. In block **1308**, constraints on bit responses are applied. Constraints applied are minimal specific energy, a maximal specific energy, and minimal and maximal drilling strength, which are calculated using Equations (10) and (11).

Using the bit responses found in block **1310**, torsional bit vibration types may be identified. The torsional bit vibration types identified may be stick-slip vibration (SS), low frequency torsional oscillation (LFTO), high frequency torsional oscillation (HFTO), high frequency torsional noise (HFTN), and/or non-vibration along drilling depth. In block **1312**, drilling depths may be separated into N sections based on the bit torsional vibration types identified in block **1310**. The N section are one or more bedding layers withing formation **120** (e.g., referring to FIG. **1**). For example, if the torsional bit vibration types change along a depth interval, the change may be indicative of a change between bedding layers or type of material within the depth interval. Thus, in block **1314**, the number of bedding layers are determined as:

$$i=1\sim N \tag{39}$$

In block **1316** for each bedding layer, rock confined compressive strength, represented as ε, and rock internal friction angle, represented as φ, are found using the methods and Equations discussed above. After identifying these variables, in block **1316**, estimated pore pressure for each bedding layer is found in block **1318** using Equation (36). The variables solved in blocks **1316** and **1318** may be used in block **1320** to determine rock unconfined compressive strength (UCS) using Equations (23) and (24). After identifying UCS in block **1320**, the variables P_0, ε_0, and φ are stored along with other bit wear status related variables in block **1322**. In block **1324**, it is determined if i<N. If i is not less than N, then blocks **1314**-**1324** are repeated until i equals to N, which concludes workflow **1300**.

FIG. **14** illustrates workflow **1400** for identifying bit wear of drill bit **102** (e.g., referring to FIG. **1**) and/or unconfined compressive strength (UCS) at a depth within formation **120** during drilling operations in real time. In real time is defined as every second or every few seconds.

Workflow **1400** may begin with block **1402** in which constants for drill bit **102** (e.g., referring to FIG. **1**), such as ζ, γ, and critical depth of cut (CDOC) are found utilizing the methods and Equations discussed above. In block **1402**, a pre-determined depth interval is chosen by an operator. The depth interval is a space between two selected depths within borehole **118** which is formed in formation **120**. After determining constants of drill bit **102** in block **1402** and a pre-determined depth interval in block **1404**, a depth of cut is calculated, represented as δ, using measurements taken by sensor packages **224** (e.g., referring to FIG. **2**) on drill bit **102**.

Measurements taken may comprise depth, revolutions per minute (RPM), rate of penetration (ROP), weight on bit (WOB), and torque on bit (TOB) all sampled at least at 1 Hz. Additionally, in block **1408**, downhole mud pressure, P_m, measured by sensor packages **224** on drill bit **102** are recovered or calculated using mud weight and vertical depth values. In block **1410**, constraints on bit responses are applied.

In block **1412** rock confined compressive strength, represented as ε, and rock internal friction angle, represented as φ, are found using the methods and Equations discussed above. After identifying these variables, in block **1412**, estimated pore pressure is found in block **1414** using Equation (36). The variables solved in blocks **1412** and **1414** may be used in block **1416** to determine rock unconfined compressive strength (UCS) using Equations (23) and (24). After identifying UCS in block **1416**, the variables P_0, ε_0, and φ are stored along with other bit wear status related variables in block **1418**. For example, if the variables change along a depth interval, the change may be indicative of a change between bedding layers or type of material within the depth interval. In block **1420**, an operator determines if workflow **1400** may continue for another interval. If another interval is desired by personnel, blocks **1406-1420** are performed again. However, if drilling operations have completed, another interval may not be sought. FIG. **15** illustrates workflow **1500** for verifying rock confined compressive strength (UCS) and bit wear of drill bit **102** (e.g., referring to FIG. **1**) from workflow **1300** or workflow **1400**. For example, workflow **1500** may begin with block **1502** in which bit operational parameters are measured during a drilling operation, bit operational parameters may be revolutions-per-minute (RPM) and Rate of Penetration (ROP). In block **1504**, during drilling operations, drill bit responses are measured. Drill bit responses may comprise weight on bit (WOB) and/or torque on bit (TOB).

In block **1506**, estimated rock CCS for a depth section is found using workflows **1300** or **1400**. In block **1508**, estimated bit wear is found using workflow **1300** or **1400**. The CCS from block **1506** and the bit wear form block **1508** are utilized as inputs for a Bit-Rock Interaction Simulator in block **1510**. Additionally, measured bit operational parameters form block **1502** are used as inputs in block **1510** for the Bit-Rock Interaction Simulator.

In block **1510**, the Bit-Rock Interaction Simulator, takes RPM, ROP and CCS as its inputs. It calculates the engagement area and engagement shape of each cutter, then it calculates axial force, radial force and tangential force on each cutter. The WOB is the sum of all cutter axial forces. The TOB is the sum of cutter tangential force multiplied by its radial distance to bit axis. The outputs from block **1510** may be compared to the measured weight on bit (mWOB) in block **1504** and in block **1514** to verify measurements and accuracy of data.

In block **1514**, measured WOB and cWOB are compared to each other as well as TOB and cTOB using the following Equations:

$$\frac{|mWOB - cWOB|}{mWOB} < \alpha \tag{40}$$

$$\frac{|mTOB - cTOB|}{mTOB} < \alpha \tag{41}$$

where α is a pre-defined acceptable ratio such as 25% or less. In other examples, a pre-defined acceptable ratio may be 5%, 10%, 15%, 20%, and/or the like. The ratio is chosen by personnel. If the results are less than a, then the rock UCS and bit wear estimation are confirmed in bloc **1516**. If the results are more than a, then an investigation of the method in block **1518** is performed. For example, if the variables change along a depth interval, the change may be indicative of a change between bedding layers or type of material within the depth interval. This investigation determines if the input bit constants γ and/or ζ the cutter wear severity, the number of rock layers are correct or need to be changed to reflect actual conditions downhole.

Improvements over current technology are found in estimating rock unconfined compressive strength and rock internal friction angle along well depth and estimating bit wear statues to help drilling engineer to make a decision to pull out the bit. Specifically, improvements are found in that weight on bit, torque on bit, bit revolutions per minute and surface rate of penetration are measured using a sensor package disposed in a drill bit. The well depth is divided into sub-sections using torsional vibration signals to ensure each subsection is associated with only one type of rock. Then calculate bit-related variables from each bit design which are γ and ζ, which currently are assumed for all values of a drill bit. Various constraints are developed and applied to the data sets to ensure the estimation makes sense. The estimated CCS is further validated by our in-house bit-rock interaction model. Overall, improvements are found in real time estimation of rock USC and internal friction angle along drilling depth, real time estimation of PDC bit wear statues along drilling depth. If friction energy is exponentially increased with drilling depth, it indicates bit wear is significant and it is time to pull out the bit, and drilling optimization for estimate drill ahead ROP. The systems and methods for identifying bit wear and formation layers may include any of the various features of the systems and methods disclosed herein, including one or more of the following statements.

Statement 1. A method may comprise identifying a depth interval during a drilling operation as a distance between a first depth and a second depth, measuring one or more drill bit responses within the depth interval using a sensor package disposed on the drill bit, and identifying one or more torsional bit vibrations within the depth interval from the one or more drill bit responses. The method may further comprise identifying one or more bedding layers of the formation within the depth interval from the one or more torsional bit vibrations, identifying a confined compressive strength (CCS) and an unconfined compressive strength (UCS) for each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations, and identifying a bit wear of the drill bit within each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

Statement 2. The method of statement 1, wherein the one or more drill bit responses are revolutions per minute (RPM), rate of penetration (ROP), weight on bit (WOB), or toque on bit (TOB).

Statement 3. The method of statements 1 or 2, wherein the one or more torsional bit vibrations are stick-slip vibration (SS), low frequency torsional oscillation (LFTO), high frequency torsional oscillation (HFTO), high frequency torsional noise (HFTN), or non-vibration along the depth interval.

Statement 4. The method of statements 1, 2, or 3, further comprising applying one or more constraints to the one or more drill bit responses.

Statement 5. The method of statement 4, wherein the one or more constraints are a minimal specific energy, a maximal specific energy, and a minimal and a maximal drilling strength.

Statement 6. The method of statements 1-4, further comprising calculating one or more drill bit constants.

Statement 7. The method of statement 6, wherein the one or more drill bit constants are a cutting force inclination coefficient, a bit constant γ, and a critical depth of cut.

Statement 8. The method of statements 1-5 or 6, further comprising, calculating a pore pressure.

Statement 9. The method of statement 8, further comprising using the pore pressure to identify the UCS.

Statement 10. The method of statements 1-5, 6, or 8, further comprising measuring a downhole mud pressure with the sensor package.

Statement 11. The method of statement 10, further comprising using the downhole mud pressure to identify the UCS.

Statement 12. The method of statements 1-5, 6, 8, or 10, wherein the drill bit further comprises a shank.

Statement 13. The method of statement 12, wherein the sensor package is an insert that is disposed in the shank of the drill bit.

Statement 14. The method of statement 12, wherein the sensor package is disposed in a recessed area of the shank in an exterior of the drill bit.

Statement 15. A system may comprise a drill bit. The drill bit may comprise a shank, a bit body connected to the shank, and one or more blades connected to the bit body. The system may further comprise a sensor package disposed on the drill bit. The sensor package measures one or more drill bit responses within a depth interval. The system may further comprise an information handling system in communication with the sensor package that identifies one or more torsional bit vibrations within the depth interval from the one or more drill bit responses, identifies one or more bedding layers of a formation within the depth interval from the one or more torsional bit vibrations, and identifies a confined compressive strength (CCS) and an unconfined compressive strength (UCS) for each of the one or more bedding layer using the one or more drill bit responses and the one or more torsional bit vibrations. The information handling system may further identify a bit wear of the drill bit within each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

Statement 16. The system of statement 15, wherein the one or more drill bit responses are revolutions per minute (RPM), rate of penetration (ROP), weight on bit (WOB), or toque on bit (TOB).

Statement 17. The system of statements 15 or 16, wherein the one or more torsional bit vibrations are stick-slip vibration (SS), low frequency torsional oscillation (LFTO), high frequency torsional oscillation (HFTO), high frequency torsional noise (HFTN), or non-vibration along the depth interval.

Statement 18. The system of statements 15-17, wherein the information handling system further applies one or more constraints to the one or more drill bit responses, wherein the one or more constraints are a minimal specific energy, a maximal specific energy, and a drilling strength.

Statement 19. The system of statements 15-18, wherein the sensor package is an insert that is disposed in the shank of the drill bit or the sensor package is disposed in a recessed area of the shank in an exterior of the drill bit.

Statement 20. The system of statements 15-19, wherein the sensor package further measures a downhole mud pressure with the sensor package and the information handling system further uses the downhole mud pressure to identify the UCS.

For the sake of brevity, only certain ranges are explicitly disclosed herein. However, ranges from any lower limit may be combined with any upper limit to recite a range not explicitly recited, as well as, ranges from any lower limit may be combined with any other lower limit to recite a range not explicitly recited, in the same way, ranges from any upper limit may be combined with any other upper limit to recite a range not explicitly recited. Additionally, whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range are specifically disclosed. In particular, every range of values (of the form, "from about a to about b," or, equivalently, "from approximately a to b," or, equivalently, "from approximately a-b") disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values even if not explicitly recited. Thus, every point or individual value may serve as its own lower or upper limit combined with any other point or individual value or any other lower or upper limit, to recite a range not explicitly recited.

Therefore, the present examples are well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular examples disclosed above are illustrative only and may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Although individual examples are discussed, the disclosure covers all combinations of all of the examples. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. It is therefore evident that the particular illustrative examples disclosed above may be altered or modified and all such variations are considered within the scope and spirit of those examples. If there is any conflict in the usages of a word or term in this specification and one or more patent(s) or other documents that may be incorporated herein by reference, the definitions that are consistent with this specification should be adopted.

What is claimed is:

1. A method comprising:

identifying a depth interval during a drilling operation as a distance between a first depth and a second depth;

measuring one or more drill bit responses within the depth interval using a sensor package disposed on a drill bit, wherein the drill bit comprises a shank, and wherein the sensor package is disposed in a recessed area of the shank in an exterior of the drill bit;

identifying one or more torsional bit vibrations within the depth interval from the one or more drill bit responses;

determining one or more bedding layers of the formation within the depth interval from the one or more torsional bit vibrations; and

identifying a confined compressive strength (CCS) for each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

2. The method of claim **1**, wherein the one or more drill bit responses are revolutions per minute (RPM), rate of penetration (ROP), weight on bit (WOB), or toque on bit (TOB).

3. The method of claim **1**, wherein the one or more torsional bit vibrations are stick-slip vibration (SS), low frequency torsional oscillation (LFTO), high frequency torsional oscillation (HFTO), high frequency torsional noise (HFTN), or non-vibration along the depth interval.

4. The method of claim **1**, further comprising applying one or more constraints to the one or more drill bit responses.

5. The method of claim **4**, wherein the one or more constraints are a minimal specific energy, a maximal specific energy, and a minimal and a maximal drilling strength.

6. The method of claim 1, further comprising calculating one or more drill bit constants.

7. The method of claim 6, wherein the one or more drill bit constants are a cutting force inclination coefficient, a bit constant 7, and a critical depth of cut.

8. The method of claim 1, further comprising, calculating a pore pressure.

9. The method of claim 8, further comprising identifying an unconfined compressive strength (UCS) for each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations and using the pore pressure to identify the UCS.

10. The method of claim 1, further comprising measuring a downhole mud pressure with the sensor package.

11. The method of claim 10, further comprising identifying an unconfined compressive strength (UCS) for each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations and using the downhole mud pressure to identify the UCS.

12. The method of claim 1, wherein the sensor package is an insert that is disposed in the shank of the drill bit.

13. The method of claim 1, further comprising identifying a bit wear of the drill bit within each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

14. A system comprising:
- a drill bit comprising:
  - a shank;
  - a bit body connected to the shank; and
  - one or more blades connected to the bit body;
- a sensor package disposed on the drill bit, wherein the sensor package is disposed in a recessed area of the shank in an exterior of the drill bit, wherein the sensor package is configured to:
  - measure one or more drill bit responses within a depth interval; and
- an information handling system in communication with the sensor package, wherein the information handling system is configured to:
  - identify one or more torsional bit vibrations within the depth interval from the one or more drill bit responses;
  - determine one or more bedding layers of a formation within the depth interval from the one or more torsional bit vibrations; and
  - identify a confined compressive strength (CCS) for each of the one or more bedding layer using the one or more drill bit responses and the one or more torsional bit vibrations.

15. The system of claim 14, wherein the one or more drill bit responses are revolutions per minute (RPM), rate of penetration (ROP), weight on bit (WOB), or toque on bit (TOB).

16. The system of claim 14, wherein the one or more torsional bit vibrations are stick-slip vibration (SS), low frequency torsional oscillation (LFTO), high frequency torsional oscillation (HFTO), high frequency torsional noise (HFTN), or non-vibration along the depth interval.

17. The system of claim 14, wherein the information handling system further configured to apply one or more constraints to the one or more drill bit responses, wherein the one or more constraints are a minimal specific energy, a maximal specific energy, and a drilling strength.

18. The system of claim 14, wherein the sensor package is an insert that is disposed in the shank of the drill bit.

19. The system of claim 14, wherein the sensor package is further configured measure a downhole mud pressure with the sensor package and the information handling system is further configured identify an unconfined compressive strength (UCS) for each of the one or more bedding layer using the one or more drill bit responses and the one or more torsional bit vibrations and to use the downhole mud pressure to identify the UCS.

20. The system of claim 14, wherein the information handling system is further configured to identify a bit wear of the drill bit within each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

21. A system comprising:
- a drill bit comprising:
  - a shank;
  - a bit body connected to the shank; and
  - one or more blades connected to the bit body;
- a sensor package, wherein the sensor package includes at least one insert that is secured, via threading and/or compression, within a recessed area formed in the drill bit, wherein the sensor package is configured to:
  - measure one or more drill bit responses within a depth interval; and
- an information handling system in communication with the sensor package, wherein the information handling system is configured to:
  - identify one or more torsional bit vibrations within the depth interval from the one or more drill bit responses;
  - determine one or more bedding layers of a formation within the depth interval from the one or more torsional bit vibrations; and
  - identify a confined compressive strength (CCS) for each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

22. The system of claim 21, wherein the sensor package is configured to identify a bit wear of the drill bit within each of the one or more bedding layers using the one or more drill bit responses and the one or more torsional bit vibrations.

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